COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

BAY STATE GAS COMPANY	))))))	**D.T.E. 05-27**

INITIAL BRIEF OF THE ATTORNEY GENERAL

Respectfully submitted,

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I. INTRODUCTION

Pursuant to the briefing schedule established by the Department of Telecommunications and Energy ("Department") in this proceeding, the Attorney General submits his Initial Brief responding to the Petition of Bay State Gas Company ("Bay State" or "Company") for a general rate increase of $22.2 million per year, an increase of 4.7% over 2004 revenues (the "Petition" or "Filing") under G. L. c 164, §§ 1E and 94. In addition to this general rate increase, the Company is proposing annual increases for inflation, pipe replacements and changes to pension and pension related benefit costs. In addition, Bay State Gas requests approval of a price cap performance-based regulation ("PBR") plan under which the Company proposes to adjust its rates annually for five years.

As is customary in a rate proceeding, the Attorney General will provide his final recommendations concerning the Company's revenue requirements in schedules attached to his Reply Brief. The Attorney General reserves the right to respond to any issue related to late-filed discovery or record request responses in his Reply Brief.

II. OVERVIEW

On April 27, 2005, Bay State petitioned the Department for approval of a $22.2 million increase in its base rate charges for gas distribution service. In addition, the Company seeks approval of (1) a performance-based regulation plan ("PBR"), (2) a steel infrastructure replacement program ("SIR") and cost-recovery mechanism, and (3) a pension and post-retirement benefits other than pension ("PBOP") cost-recovery mechanism.

The base rate delivery charges for a typical residential heating customer will increase by approximately $5 per month on average, $60 annually. After the first year, the proposed inflation adjustment, pipe replacement adjustment, and pension and related benefits' adjustment are expected to increase rates by an additional $7 million or 4% each year. The cumulative rate increase requested over the next five years is 35%, not including increases to gas supply costs that the Company simply passes through to customers.[1]

In 1998, Bay State was acquired by a larger corporation, Northern Indiana Public Service Company, now NiSource, a public utility holding company headquartered in Merrillville, Indiana. In the merger proceeding, NiSource promised to lower costs for customers as a result of greater efficiencies and economies of scale. While no rate reductions came for customers, the Company's shareholders profited handsomely, earning more than11.8 % return on their investment in 2003 and 10.5 % in 2004. The Department has not set rates recently for any other Massachusetts utility using such high returns. *See, e.g., Boston Gas Company d/b/a KeySpan Energy Delivery New England*, D.T.E. 03-40, p. 364 (2003) (10.2 percent).

Although Bay State states that it has not been before the Department in a contested proceeding for a general increase in its base rates since 1992, in D.P.U. 97-97, the Company did

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[1] EIA estimates that the average residential price for natural gas will be almost 14% higher in 2005/06 than in 2004/05. http://www.eia.doe.gov/emeu/steo/pub/contents.html.

receive two annual rate increases in 1998 and 1999 as a result of a settlement with the Attorney General.[2] The two-year rate plan included in that settlement allowed the Company to collect a general revenue increase of $1.8 million in year one and an additional $1.8 million beginning in year two "to recover expenses incurred from investments in mains and equipment maintenance." *Bay State Gas Company,* D.T.E. 97-97, p. 2 (1997).

Despite the Company's receipt of funds from this settlement to address its main replacement and repair after the NiSource merger, the record in this case demonstrates that the Company has deferred needed maintenance in general, and particularly the replacement of bare steel pipe during the period covered by the merger rate freeze. According to the Company's own records, Company-wide bare steel main abandonments from 1998 to 2002 declined 64% after the merger and abandonments in the Brockton Division plummeted by 68%. As a result of this disinvestment, the Company now claims that there is a "crisis" and that it needs a steel infrastructure replacement mechanism so that it can receive dollar-for-dollar recovery of future investments.

The evidence in this case also demonstrates that the Company initially deferred maintenance and replacement of mains and then loaded the test year with inflated capital additions and high levels of expenditures. While the system was deteriorating, the Company was earning excessive returns. In addition, NiSource was taking capital that it should have invested in Bay State and used it to support the holding company which was over-extended as a result of its merger activity.[3] The Department should not reward Bay State by forcing its customers to

[2] These increases were specifically for the Company's mains and services. Exh. AG 2-48.

[3] Shortly after its acquisition of Bay State, NiSource acquired Columbia Gas on November 1, 2000. As a result of the merger, NiSource's debt ratio rose to about 70% in the year following the purchase.

invest in the Company's SIR Program. The Company and its shareholders should now bear any costs incurred to rehabilitate the distribution system and the Department should not allow the Company to charge customers, who suffered from the prior lack of routine maintenance and plant replacement, for those costs.

The Company knowingly delayed main replacements during the NiSource merger rate freeze to improve earnings at customer expense. The Department disallows deferral of costs during a rate freeze to be recovered later from customers for good reason: customers are entitled to enjoy the full benefit of the frozen rates, not simply a deferral of costs. In addition, the Company was given funds in good faith specifically for this type of main and service replacement in the D.P.U. 97-97 settlement with the Attorney General in the form of rate increases over two years. After just two years of increased main replacement activity, the Company simply pocketed the rest of the funds and now asks for more.

The deferred replacement of mains increased corrosion leaks, placing customers and public safety at increased risk. There is no surprise that the Company experienced an increase in its rate of leaks per mile after it slowed its replacement of bare steel mains in the Brockton Service territory. The results of the Company's actions were quite predictable. The Department's acceptance now of accelerated replacement under the SIR at customers expense would put its stamp of approval on similar actions by all utilities within its jurisdiction under merger rate freezes. The Company could correct its past misjudgment by a program of prioritizing the replacement of mains by severity of pipe condition. In fact, Northern Utilities, Inc. ("Northern"), a wholly owned subsidiary of Bay State and managed by some of the same

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Exh. UWUA 4, p. 18

witnesses that appeared in this proceeding for Bay State, recently reduced its leak rate to modest levels on bare steel by using a system of accelerated replacement of the most risky pipe first, rather than the "geographic" approach proposed by Bay State. *Northern Utilities*, DR 91-081 (1992). Northern accomplished this goal after replacing a little less than fifty percent of its bare steel main. *Northern Utilities*, DG 99-127 / DG 00-177 (2000). Bay State proposes to replace one hundred percent of its unprotected steel mains and services under its "geographic" approach in order to reduce its rate of corrosion leaks -- a far more costly approach for customers.

The price cap mechanism proposed by the Company already has features to provide for additional costs the Company may need to accelerate main replacement, so the additional payments under SIR are unnecessary. First, the PBR mechanism automatically increases the cast-off rates each year to a level sufficient to cover costs that can reasonably be expected from plant replacement. Exh. DTE-AG-2-1. Second, the PBR mechanism features an earnings sharing mechanism that would provide protection to the Company if a prudent replacement plan cause a severe earnings shortfall.

While the Company was failing to provide needed plant replacement to its system, Bay State was paying its management and officers exceptionally generous pay and benefits, including expensive automobile allowances and extravagant travel and entertainment.[4] At the same time, the Company has severely cut physical and clerical staff which had a negative impact on maintaining quality customer service.[5] In 1998, the Company outsourced its line location

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[4] This includes allocated expenses related for NiSource's $12.5 million Raytheon Hawker 800 XP jet. Exh. AG-1-54; http://www.netjets.com/Fleet/Raytheon_Hawker_800XP.asp

[5] Bay State's staffing has plummeted since its high point in 1998. Total employment dropped from 861 in 1998 to an average of 554 for 2004 (the test year). Exh. UWUA 4, p. 33. This does not include the approximately 100 workers at the Springfield call center which the Company plans to outsource to IBM

function with disastrous results -- the house explosion killed two people, injured seven more, and damaged 68 other houses.[6]

The Maine and the New Hampshire Public Utility Commissions have both investigated the Company's call center.[7] The New Hampshire Commission fined Bay State's New Hampshire subsidiary, Northern Utilities, Inc., five times in the first half of 2003 for failure to meet call center performance requirements.[8] The Maine Commission staff conducted a study of the Call Center, placing on average 5 calls per day in a 19-week period between June 2001 and November 2002, and found that the Call Center answered only 40% of the trial calls. The Company's problems led the Maine Commission to question whether the utility still retained the ability to provide adequate service in several areas apart from call center response, such as its capacity to respond to large scale outages and other service emergencies. Tr. 10, p. 1644; Tr. 12, p. 2034. The record in this case demonstrates that because the Company lacked the appropriate level of staff members, it removed a trunk line at its call center at one point so that customers would receive a busy signal and fewer calls would go into the queue. Tr. 20, pp. 3331-3332. Calls never received are not reported for the purposes of the Department's Service Quality Standards[9] and put customers at risk because they cannot reach the Company to respond to

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even though the costs of these employees remain in its requested rate increase.

[6] *See* Exh. AG-2 (1998 Attleboro house explosion incident report in which the Department found that the locator failed a drug test after the incident.)

[7] The Attorney General's request to investigate Bay State's service quality filings is pending with the Department. *See Bay State Gas,* D.T.E. 03-10, Attorney General Comments.

[8] The New Hampshire, Maine and Massachusetts companies all share the Springfield call center.

[9] As the Department noted in the Bay State/NiSource Merger docket, D.T.E. 98-31, p. 31, "an SQI is an important bulwark against deterioration in a company's service to its customers", however, the "gaming" of the metrics, through such devices as shutting down the phone lines, denies the Department

service emergencies. The Department should open an investigation and audit both the Company's service quality and its management.[10]

Ensuring the safe operation of the State's electric and gas systems is one of the Department's most important roles and responsibilities. There is no "reasonable" rate for service that is substandard, and the Department should not reward Bay State for its performance with a rate increase.

The Company's poor operating performance justifies the Department's heightened scrutiny of the Company's proposed increases in costs. The Company's reasonable rate of return in the test year, coupled with the various individual adjustments to the Company's revenues and costs recommended below, provide the Department with more than sufficient basis to deny Bay State Gas its requested initial increase in rates.

The Company's actions contravene the Department's expectations for acquisitions and mergers and the Department should correct the damage done. The Department stated in its Acquisitions and Mergers order:

> The Department is interested in all measures that will promote efficiency by discouraging waste, increasing productivity, and improving service reliability in order to lower costs for all customers ... In an increasingly competitive market, mergers or acquisitions may represent one of many measures that could achieve savings, efficiencies, increased reliability, and better quality of service ... The Department expects utilities to explore thoroughly all cost-savings measures and potential opportunities to achieve efficiencies of all kinds ... Evidence of success in these areas will be expected in rate cases.

Acquisitions and Mergers, D.P.U. 93-167-A, p. 5 (1994).

The Department emphasized improved reliability and lower costs to all customers. The

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the ability to retain its statutory oversight of a company's service quality.

[10] *Boston Edison Company.*, D.P.U. 85-266-A/271-A (1986); *Commonwealth Edison Company*, D.P.U. 89-114/90-331/91-80 Phase I (1991).

order does not discuss paying shareholders from funds historically used to maintain, replace and upgrade a company's infrastructure. A natural gas utility cannot neglect an infrastructure without putting customers and neighboring communities in peril. Bay State Gas Company has done just this. After the acquisition by NiSource, Bay State significantly reduced capital spending and used the cash for additional investment in the form of acquisitions. Although Bay State and NiSource did not petition the Department for authorization to recover the acquisition premium, they still managed to use customer-generated funds to further corporate ambitions while paying little mind to their public service obligations in Massachusetts. What Bay State and NiSource have done is antithetical to the Department's vision of utility acquisitions and mergers.

The Company comes before the Department now seeking not only to recover costs for capital items that should have been in service and depreciating long before the test year, but also it seeks a bail-out of the dangerous situation that the Company has created for itself, its customers and the communities it serves. The Department should not approve the proposed SIR bail-out under any conditions, as discussed below. Furthermore, the Department should defer the implementation of the proposed PBR program until such time as the Company can demonstrate that it has repaired the damage caused by its negligence. The Department should require a management audit of the Company. The scope of the audit should include the identification of infrastructure deferrals and recommendations for actions to cure the current deficiencies (both structural and managerial). Until the Company reconstructs itself and meets all service quality, reliability and safety standards, the Company should not be allowed to implement any PBR program.[11]

III. PROCEDURAL HISTORY

On April 27, 2005 Bay State Gas filed with the Department a general rate case and PBR Plan including tariff schedules of proposed rates and charges designed to increase the Company's annual revenues by approximately $22.2 million, or 4.7 percent, based on a test year ending December 31, 2004. The Department suspended the effective date of the requested rate increase until December 1, 2005, and opened an investigation into the Company's proposal. Order, April 28, 2005. On May 6, 2005, the Attorney General intervened as of right pursuant to G.L. c. 12, §11E, and commenced filing discovery. On May 25, May 26, and May 31, 2005, the Department conducted public hearings at Ludlow Town Hall, Brockton City Hall, and Memorial Hall Library (Andover), respectively. On June 2, 2005, the Department convened a procedural conference to establish a schedule for discovery, hearings and briefs. At this conference, the Department allowed the Massachusetts Department of Energy Resources ("DOER"), Massachusetts Community Action Program Directors Association, Inc. ("MASSCAP"), Massachusetts Oilheat Council, Inc. ("MOC"), Massachusetts Energy Directors Association ("MEDA"), Associated Industries of Massachusetts (granted on 5/24/05), KeySpan Energy Delivery New England ("KeySpan"), NSTAR Gas Company ("NSTAR"), United Steelworkers

[11]The Attorney General reserves the right to address any late filed data or record request response in his reply brief or any supplemental briefing that may be filed in this case. The Company has failed to provide requested data in a timely fashion and has often provided incomplete responses. The Company bears the burden of proof and its actions should comport with this requirement. Neither the Department, Attorney General or any other intervenor has direct access to the data necessary to determine whether the Company's request is just and reasonable. Too often during these proceedings have the intervenors and the Department been disadvantaged by the Company's inability or unwillingness to provide prompt and complete data. The Attorney General will exercise his due process rights by responding as necessary in subsequent filings.

of America (granted on 5/24/05), MASSPOWER, and Local 273 of the United Steelworkers of America AFL-CIO-CLC to intervene as full participants.[12] The Department also allowed, Fitchburg Gas and Electric d/b/a/ Unitil, New England Gas Company, Berkshire Gas Company (Berkshire)(not mentioned at the hearing- filed on 6/1/05), and Western Massachusetts Electric Company ("WMECo") to intervene as limited participants.

On June 2, 2005, the Attorney General filed a Motion for Leave to Conduct Depositions. The Attorney General sought leave to take depositions of Ed Anderson, a R.J.Rudden Associates employee and consultant to Bay State, on issues related to the corrosion analysis performed by Bay State and the Company's Steel Replacement Program; Bay State's Call Center Manager on issues related to call center performance and staffing; and Bay State's Pipe Repair and Maintenance Manager on issues related to distribution system maintenance, repair and replacement. On June 10, 2005, Bay State filed an Opposition to the Attorney General's Motion. On July 1, 2005, the Hearing Officer denied the Attorney General's motion.

Also on June 2, 2005, the Attorney General filed a Motion to Bifurcate the proceedings in order to ease the administrative burden on the Department and all interveners and to allow sufficient time for case preparation, presentation of evidence and cross examination of witnesses. The Attorney General asked the Department to separate the general rate case from the pension mechanism, steel replacement program and PBR plan, issues that could easily be settled in a second proceeding. On June 10, 2005, Bay State filed an Opposition to the Attorney General's

[12] During the procedural conference, the Attorney General objected to the intervention by KeySpan Energy New England and NSTAR. The Hearing Officer heard arguments from the Attorney General and representative of KeySpan and NSTAR, ultimately ruling that the AG's objection to the intervention was untimely and allowing those parties to intervene as full participants. On June 3, 2005, the Attorney General filed an Appeal of the Hearing Officer's ruling. On June 7, 2005, KeySpan and NSTAR filed a response to the Attorney General's appeal, the Department has not yet issued an order on the appeal.

Motion to Bifurcate. On June 20, 2005, the Attorney General filed a Motion for Leave to Submit Additional Argument in Support of his Motion to Bifurcate and Appeal of the Procedural Schedule.

On June 3, 2005, the Attorney General filed an Appeal to the Full Commission of a Hearing Officer Ruling on Intervention and Renewed Opposition of Full Party Status of KeySpan and NSTAR. On June 6, 2005, KeySpan and NSTAR filed responses to this Appeal. On June 8, 2005, the Attorney General filed a response to KeySpan and NSTAR's responses. On June 10, 2005, Bay State filed a response to the Attorney General's Appeal.

On June 6, 2005, the Attorney General filed a Motion for Oral Argument Before the Commissioners. On June 13, 2005, Bay State filed an Opposition to this Motion. On June 10, 2005, the Attorney General filed a Motion for Leave for Entry Upon Property and Inspection. On June 15, 2005, the Attorney General filed an Appeal of the Hearing Officer's Ruling regarding the Procedural Schedule. On June 24, 2005, Bay State filed an Opposition to the Attorney General's Appeal of Hearing Officer Ruling Pertaining to the Procedural Schedule.

On June 16, 2005, the Attorney General filed a Motion to Compel Responses to Discovery. On June 22, 2005, the Attorney General filed a Motion for Leave to Submit Additional Argument in Support of his Motion to Compel. On June 22, 2005, Bay State filed an Opposition to the Attorney General's Motion to Compel.

The Hearing Officer has not yet ruled on the Attorney General's Motion to Bifurcate, Motion for Leave for Entry Upon Property and Inspection, or Motion to Compel Responses to Discovery. The Commission has not yet ruled on the Attorney General's Motion for Oral Argument Before the Commissioners or Appeal of the Hearing Officer's Ruling regarding the

Procedural Schedule

On June 8, 2005, several of the intervening parties filed a Notice of Intent to File Testimony of witnesses: DOER stated that it intended to file testimony of Alvaro Pereiro, Ph.D. on PBR and SIR reconciliation mechanisms; KeySpan stated that "it is considering submitting the testimony on the issue of bad debt" but did not identify a witness at that time; Local 273 stated its intent to file testimony of Nancy Brockway on service quality issues; and the Attorney General stated his intent to file testimony by Jon R. Cavallo on distribution systems, David Effron on revenue requirements, Jacob Pouse on depreciation, and Tim Newhard on cost of capital. On June 9, 2005, MASSCAP stated that it might file testimony by as many as 15 witnesses regarding low-income related issues. On June 22, 2005, the Steelworkers stated their intent to submit testimony by between one and five witnesses relating to call center and outsourcing issues.

The Department conducted twenty-five (25) days of evidentiary hearings between July 5, 2005, and August 11, 2005. During the 25 days of evidentiary hearings, Bay State presented numerous witnesses, each of whom offered testimony on a variety of topics with a certain degree of overlap: Stephen H. Bryant, President of Bay State, provided a general overview of the case; John E. Skirtich provided information on revenue adjustments; Steven A. Barkauskas testified on employee compensation and pension issues; Danny G. Cote, addressed the proposed steel infrastructure replacement program and plant additions; Joseph A. Ferro testified on rate design; Earl M. Robinson testified on issues relating to depreciation; Paul R. Moul testified on issues relating cost of equity; James L. Harrison testified on issues relating gas cost allocations; and Lawrence R. Kaufman testified on issues relating PBR.

On July 8, 2005, Local 273 submitted prefiled testimony of its witnesses, Nancy Brockway, Kevin Friary, Time Leary and Brian McCarthy. On July 13 and 15, 2005, the Attorney General submitted prefiled testimony of his four witnesses, David Effron, Timothy Newhard, Jacob Pous, and Jon Cavallo. Also on July 15, 2005, the DOER submitted prefiled testimony of its witness, Alvaro E. Pereira, and the Steelworkers submitted prefiled testimony of its witnesses, Jody Ajar and Helen Vonmaluski. On August 1, 2005, the Company submitted rebuttal testimony of Mr. Bryant, Mr. Skirtich and Mr. Moul, regarding various issues raised in Mr. Effron's testimony; Mr. Bryant and Mr. Cote, regarding Mr. Cavallo's testimony on the SIR program; Mr. Moul regarding Mr. Newhard's testimony on cost of capital and rate of return; Mr. Robinson regarding Mr. Pous's testimony on depreciation; Mr. Kaufman regarding Mr. Pereira's testimony on PBR; and Mr. Bryant and Mr. Cote regarding various issues raised in Ms. Brockway's testimony. The Attorney General presented oral surrebuttal testimony of Mr. Cavallo and Mr. Newhard to address the SIR program, distribution system corrosion, rate of return and common equity issues raised in the Company's rebuttal testimony.

IV. CORPORATE STRUCTURE

A. BAY STATE GAS COMPANY AND NISOURCE, INC. CORPORATE RELATIONSHIPS

Bay State Gas Company's parent corporation, NiSource, Inc. ("NiSource") was created in 1998 with the merger between Bay State Gas Company and Northern Indiana Public Service Company (NIPSCO). Exh. BSG/SHB-1, p 2-19 (16 of 58); *see also* Exh. D.T.E. 2. Shortly thereafter, in 2000, NiSource merged with Columbia Energy Group (Columbia). NiSource, headquartered in Merrillville, Indiana, is a registered public utility holding company subject to the jurisdiction of the Securities and Exchange Commission ("SEC"). *Id.* at 2-20/17 of 58.

As of January 21, 2005, NiSource had sixteen direct subsidiaries that engage in natural gas transmission, storage and distribution, as well as electric generation, transmission and distribution. *Id.* Exh. AG-1-98 Attachment (B). Four of NiSource's natural gas transmission companies are regulated by the Federal Energy Regulatory Commission ("FERC"). Exh. BSG/SHB-1, p 2-19 (17 of 58).

NiSource also has several affiliated companies that provide services to its operating companies. Id. These service companies include NiSource Finance Corp., which provides internal financing to the NiSource operating companies and NiSource Corporate Services Company ("NCSC"), which provides managerial, professional and other support services to the operating companies. *Id.* at 2-19-2-20 (17-18 of 58). NCSC provides services relating to: accounting and budget; human resources, information technology; engineering; legal; tax; corporate communications; insurance procurement; risk management; corporate credit; investor relations; real estate; internal audit; energy procurement; and supply chain non-energy procurement. *Id.* at 2-20- 2-21 (18-19 of 58). NCSC bills Bay State for the services it performs according to relevant SEC rules, and according to the NCSC/Bay State Affiliate Services Agreement approved by the SEC. Some services are allocated to Bay State, others are directly billed to Bay State. *Id.* at 2-21- 2-22 (19-20 of 58). Although these services are always available to Bay State, Bay State may also pursue other vendors of those services. *Id.* at 2-23 (21 of 58).

B. NORTHERN UTILITIES, INC.

In addition to its relationship with NiSource, Bay State shares a corporate relationship with its own subsidiary, Northern Utilities, Inc ("Northern"). Bay State acquired Northern in the late 1970s and it provides natural gas distribution service in New Hampshire and Maine. *Id.* at 2-24 (24 of 58). Bay State and Northern share an Operational Services Agreement that provides the terms and conditions relating to the way in which each company provides bills and services to each other. *Id.* The Agreement provides for the sharing of certain professional, supervisory, and technical services relating to the operations and maintenance of both Bay State and Northern's distribution systems. *Id.* at 2-27 (25 of 58). Bay State allocates to Northern all of the operational service charges it incurs on behalf of Northern using a three-factor formula based on (1) Gross Fixed Assets; (2) Total O&M Expenses (net of total management costs); and (3) Number of Retail Customers. Northern allocates costs it incurs on behalf of Bay State based on a two factor formula based on (1) Gross Fixed Assets and (2) Number of Customers. *Id.* at 2-28 (26 of 58).

V. STANDARD OF REVIEW

In reviewing the "propriety" of rate increase proposals by a utility company under G. L. c. 164, § 94, the Department must determine whether the proposed rates are just and reasonable. *Attorney General v. Department of Telecommunications and Energy*, 438 Mass 256, 264 n. 13 (2002); *Berkshire Gas Company*, D.P.U. 96-67, p. 6 (1996). Since incentive regulation acts as an alternative to traditional cost of service regulation, the "just and reasonable" standard of §94 also applies to performance-based ratemaking plans. *Boston Gas Company*, D.P.U. 96-50, p. 242 (1996) (Phase I); *Investigation by the Department of Public Utilities on Its Own Motion Into the Theory and Implementation of Incentive Regulation for Electric and Gas Companies Under Its Jurisdiction* [hereinafter cited as *Incentive Regulation*], D.P.U. 94-158, p. 52 (1995). Furthermore, for incentive plans the Department has stated:

> As a general proposition, a petitioner seeking approval of an incentive proposal shall be required to demonstrate that its approach is more likely than current regulation to advance the Department's traditional goals of safe and reliable energy service and to promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation.

Incentive Regulation, D.P.U. 94-158, p. 57 (1995). "The burden of proving the propriety of a rate increase remains with the utility seeking the increase." *Town of Hingham v. Department of Telecommunications and Energy*, 433 Mass. 198, 213-14 (2001) citing *Metropolitan District Commission v. Department of Public Utilities*, 352 Mass. 18, 24 (1967); *Wannacomet Water Co. v. Department of Public Utilities*, 346 Mass. 453, 463 (1963). The Company bears the burden of proving each and every element of its case by a preponderance of "such evidence as a reasonable mind might accept as adequate to support a conclusion." G. L. c. 30A, §1(6); *Fitchburg Gas and Electric Light Company*, D.T.E. 99-118, p. 7, n.5 (2001). If the Company fails to carry this burden, the Department must deny the Company's requested rate treatment for the proposed adjustment. *Fitchburg Gas & Electric Light Company. v. Department of Public Utilities*, 375 Mass. 571, 582-583 (1978).

VI. ARGUMENT

A. SIR PROGRAM

1. THE DEPARTMENT SHOULD REJECT THE COMPANY'S ATTEMPT TO COLLECT ACCELERATED STEEL INFRASTRUCTURE REPLACEMENTS COSTS FROM CUSTOMERS SINCE THE COMPANY DEFERRED BARE STEEL MAIN REPLACEMENTS DURING THE NISOURCE MERGER RATE FREEZE

The Department Should Reject The Company's Attempt To Collect Accelerated Steel Infrastructure Replacement Costs From Customers Since The Company Deferred Bare Steel Main Replacements During The NiSource Merger Rate Freeze

Bay State seeks approval of a $300 million accelerated replacement plan for its steel mains and services installed after the test year. The Department should deny this request because the Company has not proven it is entitled to years of rates increases under this highly unusual program. Since metals deteriorate at predictable rates based on soil conditions and other known and knowable factors, the Company should not "suddenly" find itself with what it claims is an uncontrollable pipe leak rate meriting a costly accelerated replacement program at customer expense -- especially at the expiration of a five year merger rate freeze when the Company had an obligation not to defer needed main replacement until after the freeze. The Department recently refused to approve a utility's attempt to avoid the consequences of a rate freeze by shifting costs out from freeze period:

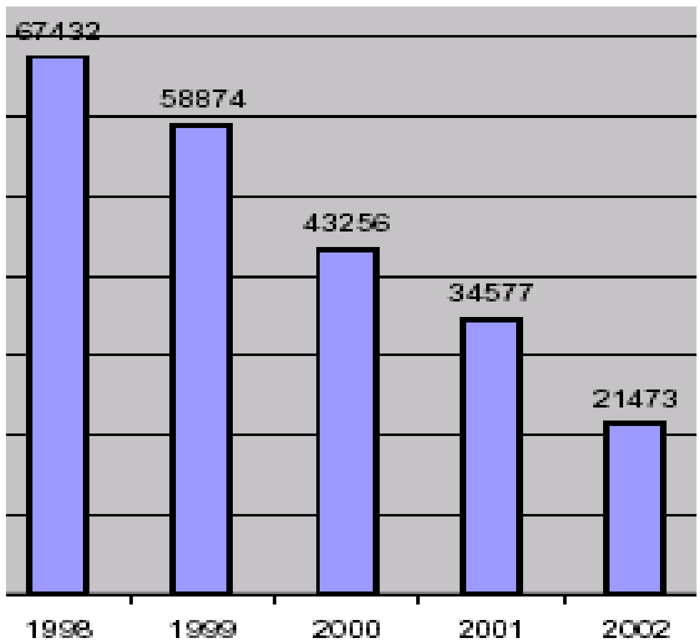
> The Department cannot permit companies to retain all potential [merger] savings realized but pick and choose the costs that will be absorbed during a rate freeze period.

NSTAR, D.T.E. 03-47-A, p. 33 (2003). *See also North Attleboro Gas*, D.P.U. 93-229, p. 6 (1993) (a utility may not defer a cost during the period covered by a rate settlement that fixes rates unless specifically allowed by the terms of the agreement). Since any alleged impending leak crisis in the Brockton area results from the Company's own decision to defer main replacement until after the merger rate freeze, the Company is not entitled to a special mechanism to charge customers the costs of the replacement of its entire remaining bare and unprotected coated steel mains and associated services in all three of its service territories.

The evidence in this case strongly supports the conclusion that the Company has deferred needed pipe maintenance in general, and the replacement of bare steel pipe in the Brockton Division in particular during the period covered by the merger rate freeze. The Department ordered the five year merger rate freeze in November of 1998. *Bay State Gas Company*, D.T.E

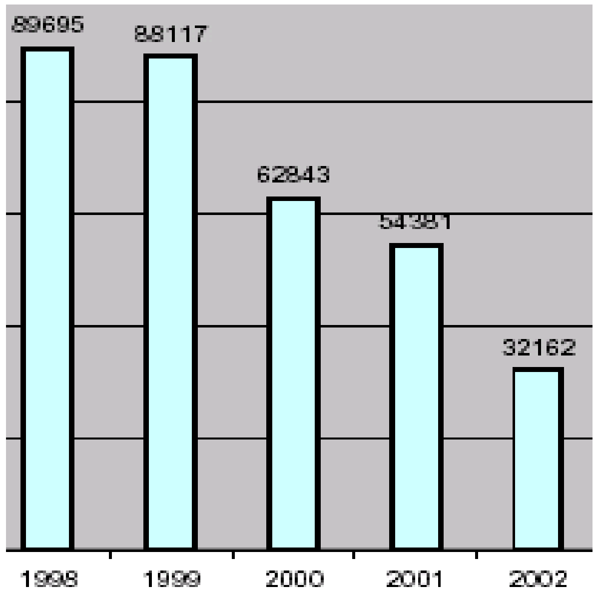
98-31 (1998). According to the Company's own records, bare steel main abandonments in the Brockton Division plummeted steadily from 1998 to 2002 from 67,432 to 21,473, representing a 68% decline.

Feet Bare Steel Main Abandonments Brockton Service Territory After NiSource Merger



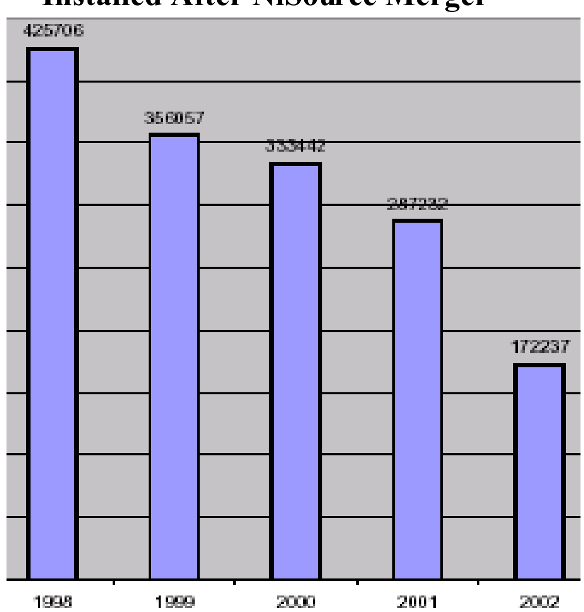
Ex. AG-2-39, 1 of 4 (showing feet of bare steel main abandonments per year in the Brockton service territory). The Brockton area is the exact service territory the Company now claims is in dire need of bare steel pipe replacement. This specific area decline was matched by a general decline in bare steel main abandonments on a Company-wide basis from 89,695 in 1998 to 32,162 in 2002.

Feet Bare Steel Main Abandonments All Service Areas After NiSource Merger



Ex. AG-2-38. These figures show approximately a 64% reduction. Ex. AG-9, p. 7, line 2. The Company had also allowed the installation of new and replacement mains to decline significantly during this same period from 425,706 in 1998 to 172,237 in 2002.

Feet Of New And Replacement Main Installed After NiSource Merger



Ex-UWUA-1-27 (graph of linear feet of main installed including new and replacement mains); *But see* Tr. 2, p. 491. Capital investment fell over 50% in the years immediately following the merger, as Transmission and Distribution related Operations and Maintence expenditures decided 2% from 1998 to 2003, in contrast to a 9.5% increase from 1993 to 1998, and the Company's slowed its efforts to reduce its unprotected steel mains. Ex. UWUA- 4, pp. 24-27. During the period between 1985 and 1997, the Company reduced its unprotected steel mains at an average of 46 miles per year. *Id*. Following the NiSource merger, this rate slumped to just 15 miles per year between 1998 and 2003. *Id*. During this same time period the Company reduced its main repair and replacement supervisors by 50% in the Brockton Division. Ex. UWUA-1-19(a). In the words of the Company's own witness: "in early 2004 we recognized, frankly, that the reductions that had occurred during the consolidation of NiSource had gone a little too deep." Tr. 2, p. 309.

The uncontested evidence also shows that the Company ordered its crews to repair, rather than replace, mains following the NiSource merger. According to a Company pipe repair crew foreman, the standing direction to the crews in recent years was to fix leaks using repair clamps, but not to consider replacing the affected section of the pipe.[13] Ex. BSG-AG-2-22, Attachment. According to the statement of the Bay State foreman, even though a worker may put a note in his work order that a given section of pipe was degraded enough for replacement, replacement of the pipe was not guaranteed. *Id*. This standing order to Company repair crews is contrary to

[13] The use of stainless steel clamps to repair bare steel mains -- a method the Company has used for many years -- can create a corrosion current that leads to accelerated localized deterioration of the main. Tr. 24, pp. 3942-3943. The Company's own Replacement Infrastructure Management system ("RIMs") lists as "Other" pipe risk factors "many clamps" and "many clamps past 10 years." RR-AG-101, Attachment A, .xls file of RIMS spreadsheet, "Input" Tab, Column BC, Rows 111 - 140.

Department of Transportation ("DOT") guidance regarding pipeline repair: "If several leaks are found and extensive corrosion has taken place, the most effective solution is to replace the entire length of deteriorated pipe." Guide Manual For Operators Of Small Natural Gas Systems, Chapter 6, Repair Methods: Plastic and Metal (Sample Guide). BSG-AG-2-25. This standing order is also contrary to the Company's own Operations and Maintence Manual, which states that if a steel mains shows sings of deterioration, Local Engineering can designate the segment as a candidate for replacement, and if a steel main is in very poor condition, the Filed Operations Leader can authorize replacement. Ex. AG-6-1, Procedure 14.15, §9. Indeed, the Company was experiencing an increasing corrosion leak rate and number of corrosion leaks from 1998 to 2000 in both the Brockton service territory and Company-wide. Ex. AG-2-1 (June 6, 2004), pp. 1 of 4 and 4 of 4, columns M & O. As noted by the Company's expert in the R. J. Rudden Report, ***"Industry studies have shown that 'when a section of pipeline system starts to develop leaks, further leaks will develop at a continuously increasing rate.'"*** AG-2-16(b), p. 4 (emphasis added). Under these circumstances, it is reasonable to conclude that the decision to defer main replacement would increase the Company's corrosion leak rate.

Bay State now asks the Department to accept the foreseeable result of its own decisions to defer main replacement in the Brockton area as the justification for the accelerated replacement under the SIR program at customer expense for the entire Company. The Department should not allow Bay State to benefit handsomely from its attempt avoid the consequences of the merger rate freeze by deferring the costs an important element of its duty to serve, and then requesting recovery for it after the rate freeze period under the guise of the accelerated steel replacement program. Customers should be entitled to the whole benefit of the entire five years of fixed distribution rates, an integral part of the Department's rationale behind approving merger rate plan, not merely deferral of rate increases. *Bay State Gas Company, D.T.E., 98-31, p. 17* ("On balance, given Bay State's historic experience of rate increases every two to five years, we believe that ratepayers are better served by a commitment now to a five-year rate freeze than by a rate-case examination of actual cost savings and cost increases at the expiration of the current rate plan.")

2. THE DEPARTMENT SHOULD REJECT THE SIR PROGRAM AS TECHNICALLY FLAWED AND NOT THE LEAST COST APPROACH TO STEEL INFRASTRUCTURE REPLACEMENT

The Company proposes to replace all of its unprotected steel mains and attached services under the SIR program, starting first in the Brockton service territory and then proceeding to Springfield and Lawrence areas. [14] Exh. BSG/DCG-1. Although the Company claims an impending leak crisis based on its leak per mile rate of 1.54 for unprotected steel mains in 2003, Exh. AG-2-1 (June 6, 2005), it does not propose to phase or prioritize its program to replace the most leaky segments of main first.[15] Exh. BSG/DCG-1, pp. 18-19. Instead, the Company proposed in its initial filing an area based approach that starts in one geographic service territory and then moves on to another, claiming this approach will allow for cheaper prices from outside contractors from economies of scale. RR-AG-87. The Department should reject this approach, and order the Company to replace its SIR mains based on a schedule that first allows, as soon as

[14] "Unprotected steel" includes bare steel, as well as coated steel without cathodic protection.

[15] While the Company predicted corrosion leaks that soon would grow beyond its control based on a rate of 1.54 leaks per mile in 2003, it had no apprehension of such a crisis in 2000 with a corrosion leak rate of 1.53 per mile during the middle of the merger rate freeze. Exh. AG-2-1 (June 6, 2004), 1 of 4; Tr. 2, p. 306. The number of corrosion leaks, as well as the rate of corrosion leaks on unprotected steel has actually declined since 2003. *Id.*

possible, the replacement of pipe segments that pose the greatest risk to public safety.[16] This approach would rapidly address any problem areas across the entire Company, rather than just Brockton, and more quickly reduce the Company's rate of corrosion leaks.

a. Bay State Departed From The Successful Method Ordered By The New Hampshire Commission For North Utilities When Proposing The SIR Program To The Department.

In 2000, Northern Utilities, a subsidiary of Bay State, reduced its corrosion leak rate to the level of just .6 leaks per mile on bare steel by using a system of accelerated replacement of the most risky pipe first. *Northern Utilities*, DR 91-081, p. 1 (1992); *Northern Utilities*, DG 99-127 / DG 00-177, pp. 2, 5 (2000). The Northern plan used a two phase method, first replacing the segments of pipe that posed the greatest risk to the public over a three year period to account for reasonable project planning, and then moving onto the less risky segments. *Northern Utilities*, DR 91-081, pp. 1, 7. Northern agreed to remove from service the worst pipes first on an accelerated basis, as recommended by the New Hampshire Commission gas safety engineer and a representative of the Office of Pipeline Safety from the Department of Transportation ("DOT"). *Id.*, p. 8. The success of this safety first approach is evident: the New Hampshire Commission terminated payments under the accelerated program after the replacement of just a little under half bare steel mains. *Northern Utilities*, DG 99-127 / DG 00-177, pp. 5 – 6 ("the replacement program was implemented to minimize active corrosion and gas leaks and has accomplished those objectives").

In contrast to the Northern case, Bay State here proposes to replace one hundred percent

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[16] The Company has committed to increasing its rate of main replacement under the SIR program, and apparently seeks payment from rate payors only for the "acceleration" of replacements above these stepped-up levels.

of its unprotected steel mains and services under its "geographic" approach, rather than addressing the most risky segments of pipe first and then reviewing its leak rate to determine the need for continued accelerated replacement at customer expense. Mr. Jon Cavallo, the Attorney General's corrosion expert agrees with Northern, the New Hampshire gas safety engineer and the DOT by advocating for the replacement of the worse performing pipe segments first. Exh. DTE-AG-2-6 ("As an engineer who must consider public safety paramount, Mr. Cavallo would not favor the Company's geographic area-based approached to prioritizing replacements, if that system leaves high risk pipe segments in the ground that threaten public safety.") Replacing the most at risk segments first is sound corrosion mitigation engineering. Tr. 17, pp. 2771-2773.

b. The Company Will No Realize Savings With It "Geographic" Approach To SIR Because It Must Replace All Segments Of Unprotected Steel Main In All Service Areas Eventually

Although the Company claims cheaper bid prices from its "geographic" approach because smaller segments of pipe yield higher bids RR-AG-87 (up to 20% cheaper bid prices per foot of installation for segments over 1000 feet, as compared to segments up to 300 feet); Exh. DTE-3-28, it has not produced a study demonstrating that the most risky segments of pipe are, in fact, all small and widely disbursed . Furthermore, since the Company plans to replace all of its pipe segments at some point - both long and short - it will not realize net savings in the long run even if longer segments are cheaper to replace because the Company will, some day, need to pay for the replacement of the shorter and more costly segments regardless of where they are located in its distribution system. The Company's definition of the length of a pipe segment involves a considerable degree of ambiguity:

> A segment is typically technically described as a length of pipe on a given street installed at the same time -- same diameter and same time. So, for example, on Main Street a segment might be -- where particularly on long streets, where there are a number of segments that were laid over years, a typical segment might be the 4-inch line that was laid in 1932 versus the 4-inch line that was laid in 1934.
>
> But programmatically, we can describe that in other ways. A segment can be nothing more than, if we think about the SIR program, a segment that the operating or engineering people discuss can be nothing more than a given segment that was put out to bid to replace.
>
> So there is no single technical answer to what constitutes a segment.

Tr. 21, pp. 3456-3457. Under such a flexible definition, it is unclear whether the most at risk segments are indeed the shortest. The Company can aggregate sections of pipe into "segments" for purposes of sending the replacements out to bid, so it should be able to realize economies of scale from a bid that includes a group of small segments.

c. The Company's "Geographic" Approach Minimizes The SIR O&M Credit Under Accelerated Steel Replacement.

By not replacing the worse performing mains first, these pipes will continue to leak at an accelerating rate. Exh. AG-2-16(b), p. 4. This dynamic will have some important influences on the SIR program. First, leaking mains will require additional O&M expenditures for repair, which will reduce the benefit customers would receive from the O&M credit under the SIR cost calculation. Exh. DTE-3-34, 1 of 12 (calculating SIR adjustment); *See e.g.*, Exh. AG-2-1 (August 25, 2005) (showing for 2004 the unprotected coated steel main in Lawrence with a leak rate of 3.67 leaks per mile while the leak rate for bare steel in Brockton was 1.40 leaks per mile). Second, these leaky mains will put upward pressure on the Company's leak rate per mile, which will help ensure that the Department does not terminate the recovery for accelerated SIR costs before one hundred percent of the mains are replaced, as the New Hampshire Commission did to

Northern. Exh. DTE-AG-2-5 (leak rate can be high while total number of leaks can be trending downward due to system improvements). In light of these arguments, the Company has not demonstrated that it has proposed a least cost approach to main replacement. Instead, the Company has proposed the most costly way to address its corrosion leak rate.

d. The SIR Program Suffers From Several Technical Problems

The Company's SIR program suffers from additional technical problems which render it an unreliable regulatory approach. As explained by Mr. Cavallo, the Company did not conduct a root cause analysis to determine the reason for its accelerating leak rate. Exh. AG-7, pp. 7-9; *see also* Exh AG-14-14 (no documentation of root cause analysis) ("After review of its files, Bay State is unable to produce any internal reports, analyses, memos or other documents that specifically or generally address the increasing leak rate causes").[17] A root cause analysis could guide the Company as it prioritized its infrastructure replacement program, as different pipe materials can have different leak rates. Exh. AG-2-1 (August 25, 2005) (showing for 2004 the unprotected coated steel main in Lawrence with a leak rate of 3.67 leaks per mile while the leak rate for bare steel in Brockton was 1.40 leaks per mile); Exh. AG-7, p. 14 (Company commissioned study did not distinguish between bare steel and unprotected coated steel). The Department has found the root cause approach a useful tool to identify a solution for infrastructure problems in the past. *Report of the Department of Telecommunications and Energy relative to reducing the number of double utility poles within the Commonwealth, pursuant to Chapter 46 of the Acts of 2003, Section 110*, D.T.E. 03-67, p. 15 (2003).

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[17] The Company has offered an explanation for the corrosion leaks, *See e.g.*, Exh. AG 14-14, but these explanation fall far short of the detailed process involved in a root cause analysis. *Compare* Exh. DTE-AG-2-3 (steps in a root cause analysis).

The Company did estimate spending $300,000 on reports from R.J. Rudden to suggest main replacement schedules, Exh. BSG/JES-1, Workpaper JES-6, line 6, while a root cause analysis would have cost about $40,000. Exh. AG-7, p. 9. The Rudden reports, Exh. AG-2-16(a) and (b), embody basic flaws which render the results unreliable. First, when comparing its corrosion metrics to other gas companies, R.J. Rudden only focused on the performance of just one of Bay State's service areas: Brockton. Exh. AG-2-16(a), p. 1 (memo to P. French). It did not compare the overall performance of the whole Company to other regional and national gas distribution companies. Exh. AG-14-19 (c) (Supplement) (spreadsheet of DOT data used in the Rudden reports to compare Brockton Division with other regional and national companies). Since on an overall basis leak rate basis, Bay State's corrosion leak rate is better than the corrosion leak rate just for Brockton, Exh. AG-2-1 (June 6, 2005), 1 of 4 Column M and 4 of 4 Column M, R. J. Rudden did not select an appropriate comparison group for its study. It should have compared Bay State's overall performance, rather than narrowly focusing on just one division of the Company. R.J. Rudden also did not select its comparison groups to reflect the same or similar ratio of bare steel and unprotected coated steel mains as the Brockton service territory. Exh. AG-14-19 (c) (Supplement)(compare Tab "2003 Nat" Row 52, Columns M &N, with all other sample Rows) (compare Tabs "1993" to "2003", Row 1, Columns M & N with all other sample Rows); Tr. 15, p. 2414. In fact, several of the Companies in its comparison group had no unprotected coated steel, Exh. AG-14-19 (c) (Supplement), which can perform differently than bare steel from a corrosion standpoint. Exh. AG-2-1 (August 25, 2005); Exh. AG-7, p. 14. Finally, there is evidence from the initial meeting with R.J. Rudden that the company provided a predetermined $20 million level of spending under the SIR program that it wanted the expert's analysis to eventually approve. AG-14-19(a), p.1 (notes of Steve Bryant's comments at "kick off" meeting with R.J. Rudden); Tr. 2, pp. 441-444. The Rudden Reports ultimately recommended spending in this range. *Id*.

The conclusions in the Rudden Reports should be given little weight by the Department. The Company appears to have directed the analysis in favor of its desired spending rate on the SIR program, which renders the conclusions in the reports biased. The reports themselves selected inappropriate groups for comparison which render its analysis unreliable.

B. PENSION AND PBOP MECHANISM

1. THE DEPARTMENT SHOULD REJECT THE PENSION AND PBOP MECHANISM AS TOO SUBJECTIVE TO QUALIFY FOR AUTOMATIC RECONCILIATION.

The Company has proposed to collect pension expenses through a self-reconciling pension and post retirement benefits other than pensions ("PBOP") adjustment mechanism. *NSTAR*, D.T.E. 03-47-B (2003). The Department should reject the Company's pension reconciling mechanism because the tariff formula is not objective and does not require deposit of all funds collected into the respective benefit trust funds. The Company has proposed no way to determine whether the overall rates resulting from the operation of the tariff in the future will be just and reasonable. G. L. c. 164, §94 (Department must determine "propriety" of general rate increase after hearing). In the alternative, if the Department does approve the pension mechanism subject to ongoing reconciliations, the Department should also continue its practice of allowing discovery, hearings and briefs to investigate each annual compliance filing. *See NSTAR*, D.T.E. 03-47-B (Phase II) (2005).

The Company has not provided a fixed formula with objective elements, but rather seeks approval of the application of a formula with complicated variables that contain a considerable degree of subjectivity in their calculation. *See generally*, Exh. AG-4-1 to 4-23 (addressing support for the numerous formula variables); Tr. 8, pp. 1258-1309; 1347-1350, 1361-1364 and Tr. 14, pp. 2260, 2262, 2265 (discussing selection process for the discount rate, trends in compensation, healthcare cost predictions and projected trust fund returns). Small percentage changes in some of these variables results in very large dollar changes in the amount of pension expense recovered from consumers during any given year.

The proposed tariff does not require the Company to deposit all of the funds collected through the pension / PBOP mechanism into the respective trust funds. Exh. AG-4-24. The Company may use funds collected from customers through the pension / PBOP mechanism for any purpose, including enriching shareholders, instead of funding the intended trusts. This lack of dedication of funds to the respective trusts when combined with the high degree of subjectively in calculating the tariff formula variables renders the tariff defective.

As amply demonstrated by the record evidence in this case, the Bay State pension formula contains inputs that involve subjective decisions and actuarial judgement. Tr. 8, pp. 1258-1309; 1347-1350, 1361-1364 and Tr. 14, pp. 2260, 2262, 2265. It is not the type of objective, actual cost "'pass-through' provision operating in terms of a mathematical formula" approved by the Supreme Judicial Court. *Consumers Organization For Fair Energy Equity, Inc. v. D.P.U.*, 368 Mass. 599, 602 (1975). Unlike the Cost of Gas Adjustment Clause ("CGAC"), which passes through actual costs, the Company can produce no bills or invoices for these pension and PBOP costs. While the Bay State formula appears to be fixed, it contains far too many complicated moving elements to be considered fixed from one reconciliation filing to the next. The formula is defective and provides no way to determine whether the increases in rates results from it ongoing operation will be just and reasonable. The Department should reject it.

C. PBR

1. INTRODUCTION

Bay State Gas Company's proposed Performance Based Ratemaking (PBR) Plan neither caps the prices that the Company charges for distribution service, nor creates incentives for the Company to provide low cost gas distribution service, and, therefore, should be rejected by the Department.

The Department established its framework for the price cap formulas in Incentive Rate Making, D.P.U. 94-158 (1995). The Department then applied that framework in successive cases *NYNEX*, D.P.U. 94-50 (1995); *Boston Gas Company*, D.P.U. 96-50 (Phase I) (1996); *Boston Gas Company*, D.P.U. 96-50-C (1997); and *Boston Gas Company*, D.P.U. 03-40 (2003). In the first gas distribution company case, *Boston Gas Company*, D.P.U. 96-50 (Phase I) (1996), the Department found the following components to be appropriate for a first generation price cap plan:

Plan Term: 5 Years
Inflation Index: GDPPI
Net Productivity Growth
And Input Price Growth: 0.0 Percent
Consumer Dividend 0.5 Percent

Id., pp. 262-283, and 320. The Department approved slightly different terms for the first generation price cap plan for Berkshire Gas Company:

Plan Term: 10 Years
Inflation Index: GDPPI
Net Productivity Growth
And Input Price Growth: 0.0 Percent

Consumer Dividend 1.0 Percent

Berkshire Gas Company, D.T.E. 01-56, pp. 10-11 and 19-21 (2001). In the next review of Boston Gas Company's performance under the price cap plan, in D.T.E. 03-40, the Department modified the price cap mechanism to reflect the additional experience of the utility:

Plan Term: 10 Years
Inflation Index: GDPPI
Net Productivity Growth
And Input Price Growth: 0.11 Percent
Consumer Dividend 0.30 Percent

Id. pp. 473-488, and 494-497. These parameters attempt to control the Company's prices and provide incentives for the Company to control the costs for distribution service.

The PBR Plan the Company requests differ significantly from the Department's established PBR precedent. Bay State proposes that the Department reject the concept of reviewing all of the costs of distribution service when determining the relative efficiency of the company. The Company also proposes denying customers the benefit of the first generation PBR customer dividend of 0.5 percent to 1.0 percent, while also denying them the benefit of the second generation PBR term of ten years. Finally, the Company's PBR Plan removes from the price cap formula certain costs that it would like to recover dollar for dollar through reconciliation clauses, thus rendering the value of the inflation and price indexes meaningless, while undermining the whole notion of cost containment. As will be discussed below, these changes will circumvent destroy the Department's stated purpose and the expected results from a PBR Plan. Therefore, the Department should deny the Company's proposed changes to its PBR standards and instead retain the current precedent when setting the base rate for the Company in this case.

2. THE TOTAL COST ANALYSIS OF THE COMPANY'S SERVICE DEMONSTRATES THAT THE COMPANY IS NOT AS EFFICIENT AS THE INDUSTRY AVERAGE

The Company failed to show that its cost to provide gas distribution service is at or below the industry average. The Department allows a utility to use the industry average productivity offset when it can show that its cost is at or below that of the industry as adjusted for the particular characteristics of the utility. Boston Gas Company, D.P.U. 96-50 (Phase I), pp. 274-275 (1996). The evidence in the record shows that Bay State Gas Company's costs do not meet the Department's standard since they are above those of the industry average.

The Company's original filing provides an analysis performed by Mr. Kaufmann that fails to include all of the costs of providing distribution service, so therefore, fails to meet the Department's standard. Mr. Kaufmann performed regression analyses to find variables that he believed determine gas distribution companies' total operations and maintenance expense. He then used his regression model to predict the level of operations and maintenance expense for Bay State Gas Company. He compared his predicted level of O&M expense to the actual expense for 2003 and claimed that Bay State was an efficient gas distribution company since the Company's actual O&M costs were below the predicted level of costs.

A true productivity analysis of the distribution service would include an analysis of all of the costs of providing that service, the operations and maintenance expenses as well as the capital costs. Mr. Kaufmann's analysis, however, only considers operations and maintenance expense. This narrow analysis fails to provide a complete picture of the Company's costs and cannot be used to compare the total productivity to that of the rest of the industry. Therefore, without the total cost analysis, the Company has not met the Department's requirements. In fact, when Mr. Kaufmann did perform a total cost analysis, the results indicated that the Company was less productive then industry averages.

3. Mr. Kaufmann's Productivity Analysis Fails to Recognize That Bay State Gas Is Part of NiSource

Mr. Kaufman's operations and maintenance expense productivity analysis fails to properly consider important resources available to Bay State that further prove Company is less efficient than the industry average. First, Mr. Kaufmann's analysis failed to reflect the fact that Bay State is a division of a larger corporation. Utilities are expected to be more efficient the larger they are. A basic principle of economics is economies of scale, the larger a firm is the lower will be its unit cost of service. Mr. Kaufmann's analysis treats Bay State as a small standalone distribution company with just 300,000 customers, rather than a part of the second largest distribution company in the United States with over 3 million customers. This bias results in a substantial overstatement of the expected cost of service and an overstatement as to the actual efficiency of the Company.

Mr. Kaufmann's productivity analysis also fails to reflect the benefit to Bay State of its role as part of a combination gas and electric company. Mr. Kaufmann determined that utilities that are parts of combined firms with both gas and electric operations are expected to have lower costs. Bay State has an electric distribution company affiliate, NIPSCO. Although the companies do not benefit from shared meter reading resources like some other combination firms might, they retain the biggest benefit, and enjoy the economies, of a service company that provides employees who provide accounting, finance, treasury, human resource, engineering, and purchasing functions. Mr. Kaufmann's analysis fails again to recognize this reality, biasing his results by overstating Bay State's expected cost of service and an overstatement of the actual efficiency of the Company.

4. THE COMPANY SHOULD NOT BE ALLOWED TO PICK AND CHOOSE THE PARTS OF THE FIRST AND SECOND GENERATION PBRS THAT IT PREFERS

The Department should deny the Company's proposal to selectively use the individual components from the Department's standard first and second generation PBR Plans that benefit the Company the most. The Department has determined that PBR Plans should have different components depending on whether they are first generation or later generation plans. First generation plans have five-year terms, that is, five years of price cap increases after the cast off year. First generation plans also have higher consumer dividends added to the productivity factor to compensate the Company's customers for the change over from rate of return price setting to the price cap PBR regulation. On the other hand, after a utility has completed its first generation plan, the Department changes these components. The term of the plan increases from five to ten years, and the extra consumer dividend is essentially eliminated.

The Company's proposal allows it to have the best of both first and second generation PBR Plans while avoiding the worst of both. The Company believes that the five-year rate freeze that it proposed as a result of its merger with NIPSCO was a first generation PBR Plan. Thus, it proposes to eliminate the consumer dividend adder. At the same time it is claiming to have finished its first generation PBR, however, Bay State wants to the advantage of having the five-year term of the first generation PBR Plan.

The Department should reject the Company's plan to piece together the best plan possible for its shareholders. The Department has found that a rate freeze as the result of a merger is not a PBR Plan. Therefore, the PBR Plan that would result from the Order in this case would be a first generation plan. As a result, the Department should find, consistent with its precedent, that the full consumer dividend 0.5 to 1.0 percent should be added to the productivity factor and that the term of the plan should be five years.[18]

5. THE COMPANY'S PROPOSAL TO HAVE A SEPARATE ADJUSTMENT MECHANISM FOR ITS MAINS AND SERVICES INVESTMENT DEFEATS THE WHOLE PURPOSE OF THE PRICE CAP FORMULA AND PERFORMANCE BASED REGULATION.

The Company's proposal to create a separate tracking mechanism for mains, services, and related capital additions after the test year undermines the purpose of the Price Cap formula and Performance Based Regulation. The rationale underlying the Department's move away from cost based rate regulation was to provide utilities with in incentive for their management to make those decisions necessary to provide low cost service while still providing them sufficient revenues to cover those costs. Under a PBR plan, utilities were supposed to find that mix of capital and labor that provides safe, reliable service at the lowest cost without constant Department oversight. Bay State's proposal in this case defeats all of those purposes, guaranteeing higher rates, and more required oversight by the Department.

The Bay State's tracking mechanism for mains, services, and related capital additions gives the Company an incentive to act uneconomically, raising rates, to the detriment of its customers. The Company's proposal allows it to recover these post test year capital additions dollar for dollar, so it will have no incentive to minimize the costs of the capital additions. Furthermore, it will have no incentive to seek tradeoffs for other alternatives to the capital additions, like superior maintenance and leak repairs that might delay the necessity of the main

[18] If the Department finds that the PBR Plan that results from the Order in this case is indeed a second generation plan, then it should consistently follow its precedent for the second generation plan, and order the reduced consumer dividend along with a ten-year term.

replacements, since those replacements given treatment through the proposed tracking mechanism will receive dollar for dollar recovery and the maintenance and leak repair expenses will not.

The Company's proposed tracking mechanism will require much more additional oversight by the Department. The proposed mechanism is not a simple established formula that requires, like the price cap formula proposal would, a few objective numbers to be inserted each year. The Company proposes annual Department reviews of its mains, services, and related capital additions, requiring testimony, discovery, hearings, and briefs, as the parties must now micromanage the Company's investment decisions each year. Did the Company properly evaluate the mains for the number and types of leaks? Did the Company properly prioritize the mains for replacement? Should each of the replacements have been done by the Company employees or outside vendors? Was each replacement performed by an outside vendor properly put out for bid? Were the Company costs, including overheads, prudently incurred and reasonable in amount? When exactly did the plant become use and useful, providing utility service? The Department will have to answer each of these questions for each main addition. The establishment of a separate capital addition mechanism will prompt all of the other utilities under the Department's jurisdiction, including the gas, electric, and water companies, to seek similar mechanisms. Certainly, anytime utilities are replacing old lines and services, it is being done for safety and reliability purposes like Bay State's proposal in this case. Therefore, if the Department approves the Company's capital additions recovery mechanism in this case, every utility can propose the same adjustment mechanism. Every utility will then have a "mini" rate case each year as the Department has to review, under this framework, each utility's multitude of capital additions. This type of administrative oversight by the Department is not only burdensome when the Department must review the activity just for one company, but clearly unworkable as a method of review of all of the gas, electric, and water companies under the Department's authority.

The Company's proposal to remove the costs of capital additions from the price cap formula renders the inflation, productivity, and price indexes that Mr. Kaufmann determined useless for purposes of setting rates. Mr. Kaufmann's productivity analysis is based on the total costs of providing gas distribution service. This includes the operations and maintenance expenses as well as the capital costs. From this analysis he determined price indices and the productivity factor that he used for his recommendation. Now, he proposes to pull out one of the costs of providing service and decided that it alone will receive special treatment in the capital additions recovery mechanism. This scheme, however, destroys the relationship between inflation factor and the productivity factor as he has calculated them, since they are based on the all in costs. The inflation rates, price indices, and productivity factors would have to be performed excluding the capital addition costs. Mr. Kaufmann failed to perform this analysis. Therefore, using Mr. Kaufmann's proposed inflation index and productivity factor for Bay State's base rates will per se incorrectly increase rates, because of this fatal flaw. For this reason alone, the Department must reject the Company's proposal to extract capital costs out of the price cap formula and deny the proposed creation of a new capital additions recovery mechanism.

D. RATE BASE

A key component of the Company's rates is its rate base. Only prudently incurred costs of plant that is used and useful and providing utility service to customers at the end of the test year can be included in the rate base used to determine rates. *Fitchburg Gas & Electric Company*, D.T.E. 02-24/25, pp. 22-24 (2002). Bay State has overstated its rate base by not recognizing the full amount of gains on sales of its Westborough and propane properties, imprudently investing in its certain plant additions, attempting to include a GTI research funding proposal, and incorporating construction work in progress.

1. THE DEPARTMENT SHOULD REVISE THE WESTBOROUGH GAIN ON SALE

The Company sold its Westborough headquarters, consisting of a building and real estate located at 300 Friberg Parkway, Westborough, Massachusetts, on June 4, 1997 to TriNet Corporate Realty Trust, Inc., d/b/a/ TriNet Essential Facilities XXIII, Inc., a Maryland corporation ("TriNet"), for gross proceeds of $11,409,654,[19] and net proceeds of $10,145,273. RR-AG-51; Exh. AG-3-42; Exh BSG/JES, Sch. JES-6, p. 7 of 20. The Company reported a net gain of $864,829 after subtracting $9,280,444 for the net book value of the building and land. Exh. BSG/JES-1, p. 2-114; Exh. BSG/JES-1, Sch. JES-6. p. 7 of 20; AG-3-42; Tr. 9, p. 1568. The Company then reduced the net gain further by $141,832 by allocating a portion of the gain to other affiliates who paid some of the Westborough rent, leaving a remaining net gain to Bay State of $722,997. Exh. BSG/JES-1, p. 2-114.[20]

The Company has incorrectly calculated the amount of net sale gains that should flow

[19] The Westborough Purchase Agreement states the purchase price was $10.8 million plus "credits and prorations." RR-AG-49, p. 10. The Company stated that the original cost as of the date of sale was $11,409,654. RR-AG-51. Neither the buyer nor seller performed an appraisal of the Westborough property prior to sale (RR-AG-52), so the correct figure for the gross proceeds is $11,409,654. The Company has not provided the "Basic Lease Information" that was part of the original purchase and sale/lease back documents. Tr. 9, pp. 1570-1573.

[20] TriNet did not require an appraisal of the property to set the purchase price, nor does the record reflect any other explanation as to the reasonableness of the purchase price. RR-AG-52.

back to its rate payers. The Company began its calculations with the net proceeds, but it should have begun its calculation with the gross proceeds and should have itemized all costs of sale leading to the net proceeds. The Company has failed to explain or itemize the $1,264,381 of sale expenses, so the Department is unable to determine whether those sale expenses were reasonable and prudent. Consequently, the Department should calculate the net gain based on the gross proceeds amount -- $11,409,654. *Boston Gas*, D.T.E. 03-40, p. 181.

The Company also wrongfully reduced the net gain by $141,832 on the belief that certain affiliates should be entitled to share in that gain. A close review of the use of the Westborough facilities reveals that only 26 Bay State employees occupy the 88,000 square feet of office space as of July 7, 2005. RR-AG-2. The Service Company houses an additional 22 NCSC employees in the Westborough building. *Id.* The Company is subletting the remainder of the space and receiving a substantial amount of rent -- from 2002 to 2004 the sublet rent increased from $55,716 to $179,653.29. RR-UWUA-6. The Company has not identified the sublessees, provided the square footage occupied by each sublessee, or listed the square footage used for non-utility purposes.[21]

Department precedent requires the Company to adjust its cost of service for utility property that is not used for utility purposes. *Boston Gas*, D.T.E. 03-40, p. 173. This adjustment is appropriate to prevent double-recovery of a pro rata share of lease and operating costs from ratepayers. *Id.* The Company has not provided the Department and parties with the floor plans

[21]The Company leases its Westborough headquarters, consisting of a building and real estate located at 300 Friberg Parkway, Westborough, Massachusetts, on a 15-year lease for $1,122,180 annually. Exh. BSG/DGC-1, p. 57 of 63, Bay Stamp page 3-126. The Department should exclude the lease expenses included in the cost of service for the same reasons as it includes all of the gains of sale of the Westborough headquarters.

or the breakdown of square footage of the Westborough facilities attributable to utility versus non-utility operations, separated by sublessee. The Company, therefore, cannot substantiate its claim that affiliates who used the premises are entitled to any pro-rated gain from the sale, much less $141,832.

Additionally, the Company has failed to conduct a proper cost/benefit analysis comparing the economic advantages of retaining the property with implementing a sale/lease back transaction. The Department has held that: "prudent business practice would require a pre-execution analysis to determine whether it is cheaper to purchase or lease office space, in order to obtain the least expensive office space for a company's ratepayers." D.P.U.89-114/90-331/91-80, Phase I, at 96, 98. The Company failed to obtain an appraisal of the property and used a one-year analysis to conclude that the sale/lease back transaction was financially superior, but the Company should have used a 25-year period for its analysis since that is the maximum amount of time the Company could have retained the use of the property. Tr. 9, pp. 1569-1570. Without that analysis, the Company cannot determine -- or the Department review -- whether the resulting comparison would have favored retention, rather than sale/lease back.

Where the Company sells its utility property, the Department's long-standing policy with respect to gains on the sale of utility property has been to require the return to ratepayers of the entire gain associated with the sale. *Boston Gas*, D.T.E. 03-40, p. 180; *Commonwealth Electric Company*, D.P.U. 88-135/151, at 92 (1988); D.P.U. 88-250, at 35-41; *Boston Gas Company*, D.P.U. 1100, at 62-65 (1982). The Company has not complied with Department rules for allocating the gain from the Westborough sale, so the Department should increase the net gain attributable to the sale of the Westborough properties.

2. THE COMPANY HAS NOT SHOWN THAT ITS SALE OF PROPANE PROPERTIES TO ITS AFFILIATE, ENERGYUSA, WAS PRUDENT

The Company sold its propane properties to EnergyUSA, Inc., a NiSource affiliate, in 2001 and 2002 for net proceeds of $891,015.[22] Exh. AG-3-44 (Confidential); Exh BSG/JES, Sch. JES-6, p. 7 of 20, Bate Stamp page 2-177; Exh. AG-1-98(A), p. 8, 10 of 29; Exh. AG-1-98(B), p. 1, 5, 7 of 7. The Company reported a net gain of $230,203 after subtracting $574,877 for the net book value of the equipment. *Id.* The Company then reduced the net gain further by $38,398 by allocating a portion of the gain to other affiliates, leaving a remaining net gain to Bay State of $191,805. Exh. BSG/JES-1, Sch. JES-6, p. 2-177.

The same arguments set forth regarding the sale of the Company's Westborough headquarters apply to the Company's sale of the five propane storage tank properties. The Company has incorrectly calculated the share of gains from the sale of the propane properties it should return to its rate payers. The Company began its calculations with the net gain, but the Company should have started by providing the gross proceeds, itemizing and subtracting all costs of sale, and showing the net proceeds. The Company has failed to provide the sales prices or explain or itemize any of the sale expenses, which prevents the Department from determining whether the sales were prudent and whether the prices were reasonable. Consequently, the Department should calculate the net gain based on the gross proceeds amount. *Boston Gas*, D.T.E. 03-40, p. 181.

The Company admits that it did not calculate a cost/benefit analysis comparing the

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[22] Company has not produced copies of the purchase and sales agreements for these five propane storage tank facilities but has produced copies of the quit claim deeds for West Springfield, Medway, and Brockton, and the ground leases and notices of leases for the Lawrence and Taunton properties. Exh. AG-3-44. Consequently, it is impossible for the Department to ascertain the sales prices for these properties or whether the sales prices were reasonable.

economic advantages of retaining the property with implementing a sale/lease back transaction. Exh. AG-3-44(3) (Confidential). The Department is thus unable to determine whether the Company realizes greater cost savings by leasing, rather than owning, the propane properties. The Department has held that: "prudent business practice would require a pre-execution analysis to determine whether it is cheaper to purchase or lease office space, in order to obtain the least expensive office space for a company's ratepayers." D.P.U.89-114/90-331/91-80, Phase I, at 96, 98. Failure to conduct a cost/benefit analysis, especially where the purchaser is an affiliate, raises the presumption that the transaction was not arms length and may be subject to self-dealing. Furthermore, the Department has no basis upon which to determine that the portion of the propane storage tank property lease payments included in the test year cost of service are reasonable, especially since the payments are flowing from one NiSource subsidiary to another. The Company reduced the net gain by $38,398 claiming that certain affiliates and non-utilities should be entitled to share in that gain. A close review of the quit claim deeds and ground releases reveals no description of any affiliate or non-utility use of the properties, and the Company failed to explain how it reached its allocation percentages.

Where the Company sells its utility property, the Department's long-standing policy with respect to gains on the sale of utility property has been to require the return to ratepayers of the entire gain associated with the sale. *Boston Gas*, D.T.E. 03-40, p. 180; *Commonwealth Electric Company*, D.P.U. 88-135/151, at 92 (1988); D.P.U. 88-250, at 35-41; *Boston Gas Company*, D.P.U. 1100, at 62-65 (1982). The Company has not complied with Department rules for allocating the gain from the propane storage tank sales, so the Department should increase Bay

State's share of the net gain.[23]

3. The Department Should Exclude from Rate Base The Company's Imprudent Expenditures for its Plant Additions.

a. The Department Should Remove The $21,546,059 Of Customer Information System Program Costs From Rate Base

The Department should remove the cost of the Company's Customer Information System ("CIS") program from rate base. The Department has determined that non-discretionary or non-revenue producing plant investment like the CIS system must be evaluated under the prudent, used and useful standard. *Boston Gas Company*, D.T.E. 03-40, p. 82 (2003) *citing Western Massachusetts Electric Company,* D.P.U. 85-270, p. 20 (1986). The Department has also stated that in determining the prudence of the costs incurred, the competitive bidding process is one important means to measure whether a utility has controlled costs. *Boston Gas Company*, D.T.E. 03-40, p. 84 (2003). The Department removes from rate base those costs associated with imprudent solicitation of vendors. *Id*., *Massachusetts-American Water Company*, D.P.U. 95-118, pp. 45-46 (1996), *Boston Gas Company*, D.P.U. 93-60, pp. 27-29 (1993).

The Company made no effort to control or contain the costs associated with its new CIS program. Exh. BSG/DGC-11, p. 1. The CIS system was installed and the existing database was "cleansed" to make it compatible with the new system during the 1999 to 2001 period. *Id.* items List Numbers 5 and 6. The project was estimated to cost $7 million and the cost to "cleanse" the database was $1,101,600 for a total estimate of $8,101,600. Exh. DTE-3-36, pp. 28 and 36. When the final costs of the projects came in however, the total cost was $21,546,059, more than

[23] The Company agreed to supplement Exh. AG-3-44 with the propane storage tank properties purchase and sale agreements. Tr. __, p. __.

two and one-half times the original estimate. Exh. BSG/DGC-11, p. 1, items List Numbers 5 and 6. [$15,403,324 + $6,142,735].

Like many of its software projects, the Company had little regard for cost overruns when it was managing the CIS project. The Company provided no explanation for this gigantic $13 million cost overrun. Tr. 15, pp. 2545-2546; Exh. DTE-3-36, pp. 28 and 36. The project was never put out to bid. Tr. 15, p. 2545. The Company made no showing of proof that it made any effort to control costs. *Id*.

The Company's only defense for its choice of vendors for the CIS project was that IBM (the chosen vendor) "knew" the system and was therefore better positioned to "leverage off" of that knowledge base. Tr. 15, p. 2545. This "leveraging" however, is only beneficial, in this case, if it offers benefits to the Company and not IBM. Clearly, the choice of IBM did not lead to lower costs – when the final costs are two and one-half times the costs the original estimate, costs are out of control.

The fact that the Company made no effort to determine whether there was any lower cost alternative, the fact that the project that the Company chose was not put out to bid, and the fact that the final cost was two and one-half times the originally estimated cost without one word of reasoned explanation, means that the CIS costs were imprudently incurred. Therefore, the Department should remove $21,546,059 of costs of Bay State Gas Company's CIS system, since the Company has not shown that they were prudently incurred. *Boston Gas Company*, D.T.E. 03-40, p. 82 (2003) *citing Western Massachusetts Electric Company,* D.P.U. 85-270, p. 20 (1986) and *Massachusetts-American Water Company*, D.P.U. 95-118, pp. 45-46 (1996), *Boston Gas Company*, D.P.U. 93-60, pp. 27-29 (1993).

b. The Department Should Exclude From Rate Base Those Projects For Which There Are No Reports Explaining Reasons For Cost Overruns.

The Company has failed to meet the burden of proof demonstrating that certain of its expenditures for plant additions were prudent. The Department has cautioned utility companies that, because they bear the burden of demonstrating the propriety of additions to rate base, failure to provide clear and cohesive reviewable evidence on rate base additions increases the risk to the utility that the Department will disallow these expenditures. *Massachusetts Electric Company*, D.P.U. 95-40, p. 7 (1995); *Boston Gas Company*, D.P.U. 93-60, p. 26; *Berkshire Gas Company*, D.P.U. 92-210, at 24; see also *Massachusetts Electric Company vs. Department of Public Utilities*, 376 Mass 294, at 304 (1978); *Metropolitan District Commission v. Department of Public Utilities*, 352 Mass. 18, at 24 (1967).

The Company has failed to meet its burden of demonstrating the prudence of its costs for several of its plant additions. Five of the Company's projects contain no documentation to demonstrate the project was initially economic. *See* Exh. D.T.E.-3-22 Revised; Exh. D.T.E.- 3-27 Revised. Although these five projects experienced cost overruns, the Company did not provide any cost overrun description:

Project ID Number
L99D0052
B98D0093
L95D0023
B94D0068
B94D0101

Since the Company did not provide clear and cohesive reviewable evidence that these projects were economic investments the Department cannot evaluate their prudence, and ratepayers should not have to pay for these possibly imprudent costs. The Department should exclude from rate base the total cost for the five projects, $762,210. *Id.*

c. The Department Should Exclude From Rate Base Those Projects For Which There Are Excessive Cost Overruns.

The Department bases its prudence review on whether the company's actions were in fact prudent in light of all circumstances which were known or reasonably should have been known at the time a decision was made. *Boston Gas Company*, D.P.U. 93-60, pp. 24-25; *Western Massachusetts Electric Company*, D.P.U. 85-270, at 22-23; *Boston Edison Company*, D.P.U. 906, p. 165 (1982). The Company has not demonstrated that its actions were prudent in terms of projects that had cost overruns. Out of thirty-four revenue producing projects, twenty-one, or more than 60% of the projects, contained cost overruns.[24] Of those twenty-one projects, fourteen, or more than two-thirds, had cost overruns that exceeded 20% of the original estimated cost.

Project ID Number	**Project ID Number**
L2000D0022	S95D1040
B98D0065	College Highway
B98D0125	B01D0041
S98D1038	B99D0121
S98D1087	S99D1064
L97D0013	S99D1091
L97D0016	L98D0055

[24] The Company provided capital authorizations and closing reports for thirty four revenue producing projects that cost $50,000 or more. *See* Exh. DTE-3-22 Revised; Exh. DTE-3-27 Revised.

See Exh. DTE-3-22 Revised; Exh. DTE-3-27 Revised. The majority of the Company's revenue producing projects had significant cost overruns, indicating that the Company has a difficult time adequately estimating project costs, staying on budget, and mitigating significant cost overruns. The ratepayers should not have to pay for the Company's inability to either correctly estimate the budget of a project or contain costs. For these reasons, the Department should remove from rate base the cost of the fourteen projects with cost overruns that exceed 20%, $4,474,078.

d. The Department Should Remove from Rate Base the Cost of Non-discretionary Projects For Which the Company Did Not Perform a Cost-benefit Analysis or Show Cost Containment Efforts.

Non-discretionary plant investment must be used and useful in providing service to ratepayers and the expenditures must have been prudently incurred. D.T.E. 03-40, p. 82, *citing Western Massachusetts Electric Company*, D.P.U. 85-270, p. 20. For non-discretionary projects, as in revenue producing projects, prudent utility management and common business practice dictates the need for projects appropriate cost-analysis to determine the cost of the project prior to commencement. Boston Gas Co., D.P.U. 93-60, p. 27 (1993).

The Company claims that since these projects are non-discretionary, it has no choice but to complete these projects regardless of the cost or cost overruns that may occur. Tr. 21, pp. 3388-89, 3392, 3394. Then non-discretionary projects, however, may be managed well to assure expenditures are not excessive and to avoid cost overruns. The Company's recent change of procedures that now provide management with explanations of cost overruns in these projects[25] is not a cost containment measure for that project but simply a way to identify the problems to

[25] The Company changed its construction management process in early 2004 to require explanations of cost overruns in field projects. Tr. 21, p. 3388.

prevent them from happening in the future. *See* Tr. 21, p. 3388. The Company does not evaluate these projects with the intention of containing or mitigating costs as they exceed the budget. *Id*. This is not prudent behavior and ratepayers should not have to pay for the Company's unwillingness to contain costs when these nondiscretionary projects exceed the estimated budget. The Department should remove from rate base the total of the cost overruns for the Company's nondiscretionary projects listed in DTE-3-21 revised, DTE-3-21 revised supplement, and AG-1-19.

4. THE DEPARTMENT SHOULD DENY THE COMPANY'S PROPOSED ADDITION OF CONSTRUCTION WORK IN PROGRESS TO RATE BASE

The Department should deny the Company's proposed addition to rate base of Construction Work In Progress ("CWIP"). Exh. BSG/JES-1, Sch. JES-13, pp. 1 and 4. The Department has a longstanding precedent of using test-year end rate base. *Massachusetts Electric Company*, D.P.U. 92-78, p. 5 (1992) and *Bay State Gas Company*, D.P.U. 92-111, p. 64 (1992). Only prudently incurred costs of plant that is used and useful and providing utility service to customers at test year end can be included in the rate base used to determine base rates.[26]

The Company proposes to include in rate base $1,053,621 of CWIP of its total test year end balance of CWIP of $7,385,734. Exh. BSG/JES-1, Sch. JES-13, p. 1. According to the Company's revenue requirement witness Mr. Skirtich, the $1,053,621 of CWIP that he proposes

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[26] *See Fitchburg Gas & Electric Light Company*, D.T.E. 02-24/25, pp. 22-24 (2002); *Fitchburg Gas & Electric Light Company*, D.T.E. 98-51, p. 9 (1998) ("In order to qualify for inclusion in rates, a utility's plant investment must be in service and providing benefits to customers."); *New England Telephone and Telegraph Company*, D.P.U. 94-50, p. 295 (1995); *Western Massachusetts Electric Company*, D.P.U. 85-270, pp. 20-27 and pp. 60-66 (1986); *Western Massachusetts Electric Company*, D.P.U. 84-25, pp. 33-43 (1984).

to include are associated with non-revenue producing plant additions that have been completed, but, because of a lag in accounting, have not been transferred to Utility Plant In Service. Exh. BSG/JES-1, p.49. Mr, Skirtich's claims, however, are contradicted by the sworn statements of the Company's accountants and auditors. Exh. AG 1-2(8) Bay State Company 2004 Annual Return to the Department, pp. C-4, R-1, 81.

The dollar amount that Mr. Skirtich proposes to include in rate base was derived from the $7,385,734 balance of CWIP on December 31, 2004, the end of the test year. *Id.* and Exh. BSG/JES-1, Sch. JES-13, p. 1. This CWIP balance is also found on page 13, line 8 of the Company's 2004 Annual Return to the Department. This total balance, by definition, is work in progress that should not be included in rate base. *Uniform System Of Accounts For Gas Companies*, p. 33, [Balance Sheet Accounts, 1.Utility Plant, Account 107 Construction Work in Progress., Part A.][27]

On the other hand, plant additions that have been completed by the end of the test year appear in Account 106, Completed Construction Not Classified.[28] Plant Additions appearing in

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[27] Account 107 states that:

> This account shall include the total of the balance of work orders for utility plant in process of construction.

Uniform System Of Accounts For Gas Companies, p. 33, [Balance Sheet Accounts, 1.Utility Plant, Account 107 Construction Work in Progress., Part A.]

[28] Account 106 states that:

> At the end of the year or such other date as a balance sheet may be required by the Department, this account shall include the total of the balance of work orders for utility plant which has been completed and placed in service but which work orders haven not been classified for transfer to the detailed utility plant accounts.

Uniform System Of Accounts For Gas Companies, p. 33, [Balance Sheet Accounts, 1.Utility Plant, Account 106, Completed Construction Not Classified].

this account may be eligible for inclusion in rate base as Mr. Skirtich has advocated. Bay State's Account 106 has a zero balance as of a December 31, 2004. *See* 2004 Annual Report to the Department, p. 13, line 4. Therefore, the Company has reported to the Department that all of its construction at the end of the test year was, indeed, in progress and so should not be included in rate base.

The reports directly contradict Mr. Skirtch's claims that the CWIP assets in his adjustment were in service.[29] Since Mr. Skirtich is neither an accountant nor a Certified Public Account, the Department should not credit his testimony that contradicts the information of the Company's own CPAs in their reports to the Department. Therefore, the Department should deny Mr. Skirtich's proposed addition of CWIP to rate base, and reduce the rate base by $1,053,621.

E. REVENUE ADJUSTMENTS

1. ENERGY EFFICIENCY ADJUSTMENT

Lost base revenues are the revenues that a utility does not collect from its customers because of the decrease in billing quantities that result from the implementation of conservation programs. *Western Massachusetts Electric Company*, D.P.U. 94-8C-A, 95-8C-1, 96-8C-1, p. 3 (1996). The Department allows companies to recover these costs as a component of the company's conservation charge. Bay State has entered into a settlement agreement, pending Department approval that governs the Company's lost base revenue recovery. *Bay State Gas Company*, D.T.E. 04-39, Settlement Agreement §II., pp. 10-11 (August 12, 2004).

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[29]The Annual Reports to the Department are submitted under the penalties of perjury. The Company's accountant's and auditors, including the Company Controller, Mr. Robert G. Kriner, have filed their own sworn financial reports with the Department and they clearly state that there is no plant that has been completed, but not been transferred to Utility Plant In Service.

As part of the annual price cap calculation the Company proposes to adjust its prior year's revenues to account for lost revenues from energy efficiency programs implemented during the prior calendar year. Exh. BSG/JAF-3, Sch. JAF-3-1, pp. 3-639, 3-640. The Company's witness testified that the Company proposes to eliminate the recovery of lost base revenues through the Company's LDAC as part of the conservation charge component. Although the Company has entered into a settlement agreement governing the energy efficiency program and the recovery of costs, including lost base revenues, the witness testified that the Company had not consulted with the signatories before proposing to change the method of treating lost base revenue. The Department asked the Company to confer with the settling parties about the proposal and to report the outcome of the discussions in response to a record request, DTE-RR-125. Tr. 19, pp. 3025-3027. The Company, however, has not provided a response to the Department's request. The Attorney General reserves his right to comment on the response in his reply brief if appropriate.[30]

2. THE COMPANY'S REVENUES ARE UNDERSTATED

In addition to the Energy Products and & Services ("EP&S") revenues that the Company did not include in its revenue requirement determination, *see* Section VI,F5,a, the Company also erroneously excluded known and measurable revenues from the proposed dual fuel tariff provisions and increases resulting from special contract provisions. The Department should require the Company to include the additional dual fuel revenues and additional special contract revenues both of which are known and measurable changes to test year revenue levels and

[30]The Department's PBR formula is a price cap that provides for the adjustment of current rates (prices) based on an adjusted inflation index. *Boston Gas Company*, DTE 97-92, p.1 (1997). Because it adjusts current prices, not revenues, there is no need for this proposal that adjusts for lost revenues, and the Department should not approve it.

therefore are properly included under longstanding Department precedent. *Essex County Gas Company*, D.P.U. 87-59, p. 3 (1987).

a. Dual Fuel Revenues

The Company proposes new tariff terms to be included in its large C&I tariffs that will effectively impose a minimum bill requirement on dual fuel customers. The new terms result in increased revenue to the Company, Exh. BSG/JAF-3, pp. 5-6, but the Company has ignored the revenue impact that this proposal will have. In response to the Attorney General's request, the Company provided a calculation of the additional revenue that would have been generated during the test year if the provisions had been in effect. RR-AG-57. Unless this revenue is accounted for in the Company's revenue requirements, the new rates will result in an over collection of allowed costs.[31] Department precedent supports the inclusion of this type of post test year adjustment under the standard applicable to all revenue and expense adjustments, the known and measurable standard. *Fitchburg Gas & Electric Light Company*, D.T.E. 02-24/25, p. 76 (2002) and *Boston Gas Company*, D.T.E. 03-40, p.11 (2003) (Allowing adjustments to test year revenues for changes in rates).[32] The Company's revenue requirement should be reduced by $203,841 for the increased revenues related to the Company's proposed dual fuel provisions. RR-AG-57, p. 2 of 6.

b. The Company Should Include All Known and Measurable Special Contract Revenue in the Calculation of its Revenue Requirements

[31] The new tariff provisions will generate revenues in addition to the tariffed rates applied to the test year normalize bill quantities. The dual fuel provision will generate revenues based on volumes **not billed** therefore volumes that are not included in the bill determinants used to design the proposed rates.

[32] The dual fuel provision is similar to the implementation of new fees. The Company has included a revenue adjustment to reflect the fee increases it is proposing. RR-DTE-98.

The Company's filing includes a proposed adjustment to test year revenues for a single special contract in the amount of $418,748. The adjustment reflects the contract provision that requires the rates the contract customer pays to increase in proportion to the Company's base rate increases. AG-1-99. In responding to a data request, the Company found that it had overlooked another special contract related adjustment in the amount of $404,852 to reflect the customer's minimum bill provisions. The Company has indicated that it will include this adjustment in any revised cost of service calculations. Exh. AG-9-1 and RR-DTE-18.

On cross examination the Company's witness explained that several special contracts have escalation provisions. TR. 10, p. 1731. According to the witness, however, the Company did not include the post test year price escalation effects in the calculation of the Company's proposed revenue requirements. In response to a record request, the Company calculated the annual impact of the 2005 escalation as an increase of $17,050. RR-AG-59, p.1 of 2. In the response to RR-AG-59, in addition to the price escalation adjustment, the Company included the affect of the proposed distribution rate increase on another special contract customer. This amount, $7,363 should also be included in the proforma cost of service. Both of these adjustments are known and measurable changes and should be included in the proforma cost to serve. *Essex Gas Company*, D.T.E. 87-59.

3. POST TEST YEAR REVENUE INCREASES UNDER PRICE CAP REGULATED RATES--A PROPOSAL

The costs to provide EP&S and special contract services are included in the Company's total revenue requirement. The EP&S and special contract revenues are credited to the cost of service in order to eliminate any subsidy and to give the benefits to the customers that share the cost burden. As state above, the Company has the discretion to increase the EP&S charges and introduce new services. In fact, the Company plans to exercise that discretion by expanding its Guardian Care product line to include central air conditioning and has estimated that by 2007 the annual revenues will be $221,908. Exh. AG-9-47. Special contracts contain price adjustment provisions and the Company will receive potentially significant revenues from one special contract customer for services that had not commenced during the test year due to regulatory delays at FERC. Exh. AG-22-48. The Company's shareholders will be the sole beneficiaries of the cumulative effect these new and annually recurring revenue increases, while the captive distribution customers are burdened with the annual increases under the price cap mechanism. The Attorney General recommends that the Department require the Company to flow through the benefits of these additional revenues to the Company's LDAC.

F. EXPENSES

1. THE DEPARTMENT SHOULD REDUCE THE COMPANY'S DEPRECIATION EXPENSE LEVEL.

The Company requested a $28,844,934 depreciation expense for the period ended December 31, 2004. Exhibit BSG-JES-1, Schedule JES-7, page 2 of 4.[33] This request represents a $4,968,090 or 21% increase in depreciation expense above the $23,876,844 of depreciation expense that the existing depreciation rates would produce. Exh. AG-6, page 3. The Department should reject the Company's proposal and use instead a depreciation expense of $23,250,682 corresponding to plant as of December 31, 2004. This amount represents a $626,162 or 2.6%

[33] The Company's request is supported by a depreciation study developed by Company witness Earl M. Robinson (Exh. BSG/EMR-1). The Attorney General challenged the Company's depreciation expense through the testimony of Jacob Pous of Diversified Utility Consultants. Exh. AG-6.

reduction from the depreciation expense based on existing depreciation rates and a difference of $5,594,252 from the Company's proposed depreciation expense.

In its depreciation study, the Company identified several significant changes between the proposed rates and its existing depreciation rates.[34] More than 87% of the Company's requested depreciation expense increase is attributable to salvage and life changes associated with only two accounts: Accounts 376 – Mains and 380 – Services. Exh. AG-6, Schedule JP-1, page 1. The changes in depreciation rates and resulting changes in depreciation expense for Accounts 376 – Mains and 380 -- Services as of December 31, 2004 are set forth below.

Account #	Existing Depreciation Rate	Proposed Depreciation Rate	Net Change in Depreciation Expense 2004
376 – Mains			
376.1 – Cast Iron	1.3%	2.41%	$63,170
376.2 – Coated/Wrapped	1.31%	2.53%	$1,782,624
376.3 – Bare Steel	1.75%	4.76%	$76,376
376.4 – Plastic Mains	1.84%	2.17%	$416,050
376.5 – Joint Seals	4.74%	6.42%	$336,348
376.6 – Cathodic Protection	5.61%	7.55%	$160,527
Subtotal Mains			$2,835,095
380 -- Services	4.42%	5.08%	$1,509,726
Total Mains & Services			$4,344,821

The Company's depreciation rates are incorrect because the underlying net salvage and

[34] Those changes were most notably attributable to modifications in depreciation rates for accounts 321 - LNG Equipment, 376 - Mains, 380-Services, 382 - Meter Installation, 391.2 - Office Furniture and Equipment – Computer & IT Equipment, and 397.2 – Communications Equipment – Metscan Meter Interface Units (Exh. BSG/EMR-1, p. 28).

life curve values are incorrect. Instead, the Department should: (1) adopt a negative 10% net salvage value[35] for account 376-Mains to reflect reasonable, historical experience; (2) use a negative 110% net salvage value for account 380-Services as a more conservative estimate of the actual value of pipe services; (3) order the Company to perform a fully documented depreciation study that details the basis and justification for net salvage in its next depreciation study; and (4) adopt the Attorney General's proposed 68-S1.5 life-curve recommendation for plastic mains and 74-R4 life-curve recommendation for coated/wrapped steel mains as the only credible analyses in the record.

a. Account 376 - Mains Net Salvage Should Be Negative 10%, Not Negative 15%.

The Company is requesting $463,586,036 of negative net salvage for all its investment over the entire life of the plant (Exh. AG-6 Schedule JP-1 column (a), plant balances times Exhibit BSG/EMR-2 Table 3 column (e), net salvage rates). This means the Company is seeking $1.64 depreciation expense for every dollar of investment ($1 for the original investment plus 64 cents additional for expected negative net salvage). Exh. AG-6. This represents a $104,525,053 increase in the level of negative net salvage the Company is requesting for plant and service as of the end of 2004 (Exh. AG-6, Schedule JP-1 page 1 of 2, column (a) for 2004 plant balances times the existing net salvage rates Exh. BSG/EMR-2, Table 1a, page 2-3, column (e)). Of this amount, $80,060,569 is attributable to accounts 376 – Mains and 380 – Services. *Id.* According

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[35] Net salvage is one component of the overall depreciation formula. Net salvage represents gross salvage less cost of removal incurred in association with retirements. Gross salvage not only represents scrap value obtained for plant, but also reimbursements from third parties such as insurance carriers for damage property and credits for reuse when plant is returned to Company stores. Exh. AG-6, pp. 8-9. Cost of removal represents the cost incurred by the Company to remove plant, not subject to replacement activity. In situations where gross salvage is less than the cost of removal, net salvage is negative.

to the Company, it combines its forecasted gross salvage and future cost of removal to arrive at its analytically derived forecasted net salvage amount (the Company's proposed net salvage amounts do not correspond to the analytically derived values from its own historical salvage analyses) (Exh. BSG/EMR-4 page 10).

The Company's support of its proposal for account 376 is set forth on page 11 of Exh. AG-6:

A. The Company relied on historical data from 1980 through 2003 that ranged from a negative 3% to a negative 85% with an overall average of a negative 12%, and negative net salvage declined during the mid-90s but incurred far higher levels of negative net salvage in more recent years;

B. The Company performed analytical analysis to forecast future net salvage of approximately negative 22%;

C. From these items of information, the Company "anticipated" that the level of negative net salvage will increase in the future as the property ages due to local regulations and manpower requirements; and

D. The Company concludes that given the above noted considerations, its "experience and expectations" result in a negative 15% proposal.

The Company does not present a nexus between the various data points and its analysis to arrive at a negative 15%. Instead, it relies on generalized phrases, such as "anticipated" or "experience and expectations associated with potential local regulations and resulting manpower requirements" to somehow arrive at a negative 15%. The Company does not refer to any specific anticipated future local regulation that may become more onerous, so the Department should not give any support for the Company's proposal. The only claim the Company makes that may result in future manpower requirements apparently rests on a 2.75% annual inflation factor for future cost of removal expectations. However, if this was the sole remaining basis for the Company's selection of a negative 15%, then it also must be disregarded for several reasons.

First, historical data does not support the Company's premise that inflation is the sole factor to be considered for future changes in cost of removal.[36] Exh. AG-6, p. 15. Second, Mr. Robinson did not rely on his own analysis since the forecasted cost of removal was a negative 23%, yet he proposed a total net salvage of only a negative 15%. Next, the Company's regression analysis (Exh. BSG/EMR, p.4; Exh. AG-6, EMR-1) is questionable because Mr. Robinson could not explain the purpose of the R squared statistic, which underlies the linear regression analysis. Tr. 22, p. 3787. Additionally, the Company's 4% relationship resulting from the regression analysis does not credibly explain future cost of removal and fails to explain 96% of depicted historical relationship. Exh. AG-6.

Reviewing the annual and the rolling 3-year band historical information set forth on for account 376 clearly demonstrates that an increase in negative net salvage to a negative 15 is unwarranted at this time (Exh, BSG/EMR-2 at pages 7-19 and 7-20). Page 7-20 of the depreciation study reflects the 3-year rolling bands relied upon by the Company. There the Company identifies that only 2 of the last 9 3-year rolling bands exceeded a negative 10% net salvage. In fact, those two bands were negative 11.27% and negative 12.94%, both under the negative 15% proposed by the Company. Given the Company's proper recognition of cost of removal accounting even a negative 10% appears to be excessively negative. However, retention of the negative 10% does comport with the historical experience of the Company and does not rely on invalid analytical tools that are either fatally flawed or produce illogical or

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[36] While Mr. Robinson pointed out that the "Y" axis was mislabeled and should have been cost of removal along with one minor numerical error, those did not change the ultimate inaccuracy. The minor numerical error corresponded to only one data point at age 32.5 years of age and resulted in a 5% negative cost of removal rather than a negative 3%. Exh. BSG/EMR-2 page 7-19; Tr. 22, p. 3782; Exh. BSG/EMR-4; Exh. EMR-R1.

impossible values as does the Company's analytical tools.

b. Account 380 - Services Net Salvage Should Be Negative 110%.

The Company's narrative presentation for account 380 – Services can be broken down into the following components:

A. The Company relied on a 1980 through 2003 database ranging from a negative 88% to a negative 1,724% with an average net salvage of a negative 171%, and negative net salvage declined in the mid-90s but increasing in more recent years;

B. The Company performed its forecast analyses (linear trend for gross salvage, and inflation escalation for cost of removal) that resulted in a forecasted negative 400%; and

C. That the Company arrived at its proposed negative 170% after giving consideration to the overall historical data and the recent negative net salvage levels as well as its forecast analysis.

The Company identified historical values that ranged from a negative 88% to a negative 1,724%, used a flawed analytical linear regression and inflation escalation analyses, then arrived at a negative 170% net salvage for 380 – Services. The Company used a range for net salvage values from a negative 88% to a negative 1,724% and then chose a negative 170% without any specific presentation of how that particular value was selected.

Mr. Pous's lower negative 10% net salvage value for account 380 – Services is more appropriate. The Company's underlying historical data are suspect because they did not present a consistent number of services being retired by year, as set forth on pages 19 and 20 of Mr. Pous' testimony (Exh. AG-6). The Company presented significantly difference values of annual retirements for Bare Steel and Coated/Wrapped Steel Services for the period 1999 through 2004, depending on the Company document. Mr. Pous tested the Company's proposals and experience against industry information in order to assess the level of credibility that should be afforded the

Company's proposal. He demonstrated that the Company's request for account 380 is approximately 11 times greater than its negative net salvage request for account 376 – Mains. Given that Services are basically small pipes running from the larger mains in the street to the customer's delivery point, one would not expect a dramatic difference in cost of removal between the two different types of pipes. This logical relationship was confirmed by Mr. Pous' review of industry information, which indicated that the industry was experiencing a two to three time net salvage relationship between services and mains (Exh. AG-6 page 22). Thus, the Company's presentation on its face is approximately four to five times the level experienced by the industry.

Mr. Pous tested the Company's claimed reliance on more recent net salvage as part of its narrative explanation for its proposal and found that the four most recent 3-year historical bands relied on by the Company yielded values from a negative 136% to a negative 159%, all of which are less negative than the negative 170% proposed by the Company (Exh. AG-6 page 21). Mr. Pous reviewed the historical data from a materiality standpoint by analyzing those years within the last 10 years with the larger annual level of dollars retired. *Id.* There he found that the four years with the highest level of retirement activity on a combined basis during that time frame yielded a negative 110% value. *Id.* Given that the Company will be experiencing higher levels of retirements in the future as plant approaches its average service life, it is realistic for the Department to assume that the net salvage levels experienced by the larger levels of annual retirements may be more indicative of what can be expected in the future.

The Company has a policy where it abandons in place those services it can, which should result in lower levels of cost of removal, not more negative levels as the Company proposes with its negative 170% proposal. Exh. AG-6, p. 24. Mr. Pous, in performing a check of reasonableness of the results of his and the Company's results, found that the Company's proposed negative 170% value was out of line with industry averages. *Id.* The overall industry averages ranged from a negative 45% to a negative 105% depending on the index. *Id.*, p. 23.[37] The Company performed a very limited industry comparison (Exh. BSG/EMR-4 and Exh. BSG/EMR-3), which compromised the results (a negative 91% for all companies and a negative 129% for only New England companies) *Id.* These values are significantly less negative than the Company's negative 170% proposal and more aligned to Mr. Pous' recommended negative 110% net salvage level.

The Company's witness claimed that cost of removal will generally only become more negative than current levels yet proposed a significantly less negative net salvage for services (negative 55% down from a negative 75%) in the Louisville Gas & Electric Company case. *Id.* In his 1991 depreciation study Mr. Robinson proposed a significantly lower level of net salvage than that reflected in the historical data he reviewed. *Id.,* p. 22. Now in this case he increases the historical results rather than the prior decrease, even though the current levels are less negative. *Id.* The Company's use of the legal doctrine of ipse dixit ("I say it, therefore it is") as its basis for its proposal cannot be rewarded. The Department should reject the Company's proposal and adopt a negative 110% net salvage for services.

c. Life Characteristics Were Exaggerated.

The Company has proposed significant changes in the life characteristics (average

[37] Mr. Robinson recently proposed a negative 40% and a negative 55% for this account in testimonies in 2003 for Kansas Gas Services Company and Louisville Gas & Electric Company. *Id.*

service life and corresponding dispersion pattern) for certain of its investment in the various sub accounts in account 376 – Mains (Exh. AG-6, p. 28). The Company segregated its investment in mains into 6 separate categories as set forth below. *Id.,* p. 27.

Acct.	Description	P-I-S 12/31/03	ASL/Curve
376.10	**Cast Iron Mains**	**$5,710,347**	**75-R2**
376.20	**Steel Mains – Coated/Wrapped**	**$143,919,725**	**55-R4**
376.30	**Steel Mains – Bare**	**$2,564,983**	**74-R3**
376.40	**Plastic Mains**	**$116,579,215**	**55-S2**
376.50	**Joint Seals**	**$19,580,594**	**23-R5**
376.60	**Cathodic Protection**	**$7,381,476**	**19-S5**

The Company performed limited actuarial analyses in support of its proposed modifications to existing life characteristics. In establishing life characteristics for plastic mains the Company also relied on unidentified industry data (Exh. AG-6, p. 28). The Company's analysis appears to be based to a great extent on speculation and the flawed fitting of historical data in the curve fitting process of the life analysis. In establishing life and dispersion patterns for mass property accounts such as mains actuarial analyses are normally performed. Actuarial analyses attempt to identify the annual level of retirement activity by annual age intervals. This process divides the annual aged retirements by the plant exposed to retirement at the beginning of the corresponding age interval. The annual ratios of retirements to exposures are chain multiplied to derive an actual survivor pattern or observed life table. This is the same type of analyses insurance companies perform in order to establish premiums for life insurance polices. The establishment of an accurate observed life table based on historical patterns provides a realistic view of the expectation for retirements during any age interval for a homogenous group. While the Company performed actuarial analyses on its various plant accounts, it had limited or meaningful aged data for certain accounts that resulted in less than a full life curve. When an observed life table does not decline to a zero level surviving the resulting curve or pattern is called a "stub" curve. Curve fitting for situations where stub curves are produced require greater degrees of judgment to predict an appropriate life-curve combination.

The Company's curve fitting and life-curve selection for certain mains sub accounts is significantly flawed. Mr. Robinson relied on limited industry data in rebuttal Exh. AG-6, p. 33 and Exh. BSG/EMR-4 page 17. His new life analyses for plastic mains yields a 41-S2 life-curve combination (Exh. BSG/EMR-R4 and Exh. BSG/EMR-4 page 1), which is dramatically lower than the proposed 55-S2 proposal. There is no explanation for the significant difference. If there were validity to his new analyses the life-curve proposal would have to be extended as his best fit with a "T-Cut Age" of 25 years yields a 120-L1 life-curve combination (Exhibit BSG/R-R4 at Exhibit EMR-R4 page 3).

A better curve fit to the actual observed life table for plastic mains resulted in longer average service lives no mater what type of curve was selected (Exh. AG-6, pp. 29-31). Also, a longer average service life was more in line with industry expectations (*Id.,* pp. 34-35). The Attorney General's life related presentation for plastic mains is the only credible analyses in the record and should be adopted.

The Company's life curve values give unwarranted weight to very small dollar levels of retirements and exposures at the expense of dramatically larger levels (much more meaningful) during age intervals between approximately 32 years and 50 years of age (Exh. AG-6 page 37 and Exh. BSG/EMR-2 page 5-22). A better curve fit to the actual observed life table for coated/wrapped steel mains resulted in longer average service lives no mater what type of curve was selected (Exh. AG-6, pp. 39-41). Mr. Pous also relied on gradualism, a concept recognized but not used by Mr. Robinson (Exh. AG-6, p. 41). The Attorney General's life related presentation for coated/wrapped steel mains is the only credible analyses in the record and should be adopted.

d. The Department Should Require The Company To Provide Substantial Evidence For The Proposed Changes To The Average Service Lives And Net Salvage Values For The Other Plant Accounts.

The Company proposes significant changes to the depreciation accrual rates for certain other plant accounts based on Mr. Robinson's judgment. Like with the Mains and Services, Mr. Robinson's ability to justify the magnitude of his proposed changes to the average service life and net salvage value was severely lacking in many cases. Tr. 11, pp. 1791-1845. The Department must base its decision regarding any changes to the average service life and net salvage value for each plant account based on substantial evidence, not flimsy claims of judgment. Therefore, the Department should scrutinize each of the Company's proposed changes to the accrual rates to ensure that there is substantial evidence to justify the actual magnitude of each change.

2. SEVERANCE PAYMENTS MISCHARACTERIZED AS "PERFORMANCE INCENTIVES"

The Company reported a $4,189,705 accrued liability for incentive compensation in its 2004 annual report to the Department reflecting an employment agreement and a non-competition agreement. Exh. AG-1-2 (8), Bay State Gas 2004 Annual Return to the Department. The Company later produced the agreements and attached schedules in Exh. AG-11-14 (Confidential); Tr. 14, pp. 2274-2275. The Company appears to have included the 2004 incentive payments arising from these agreements in the test year cost of service as performance incentive payments. Exh. AG-11-14 (Confidential). The Service Company (NCSC) allocated $816,337 of incentive compensation to Bay State during the test year. RR-AG-43.

Under the terms of the Employment Agreement in Exh. AG-11-14, the former Bay State Gas employee was entitled to receive a substantial sum in 2004 as a "performance incentive" bonus. Exh. AG-11-14, Attachment (a), Schedule 4(a), page 12 of 13. This payment term became effective upon the employee's termination and payments were scheduled to be completed prior to the mid-point of the rate year.

The Department should disallow the 2004 portion of these payments and any associated capitalized amount and accrued liability that are contained in the cost of service because these expenses are severance payments, not performance incentive payments, and do not extend into the rate period. Severance payments reflect payment for past, not future services, provide no incentive for the terminated employee's future good performance, and therefore provide no benefit to ratepayers during the upcoming rate period. *Boston Gas*, D.T.E 03-40, p. 139;

Fitchburg, D.T.E. 02-24/25, p. 99. The Company has not demonstrated that the payment amounts were reasonable, so the Department should disallow the test year expenses associated with this terminated employee. *Id.*

The Department considers three classes of expenses recoverable through rates (a) annually recurring expenses are eligible for full inclusion in cost of service unless the record supports a finding that the level of the expense in the test year is abnormal, (b) periodically recurring expenses are normalized so that the cost of service will include only the appropriate portion of the expense, and (c) non-recurring expenses that are so extraordinary in nature and amount as to warrant their collection are amortized over an appropriate period. *Fitchburg Gas and Electric Light Company*, D.P.U. 1270-1414, pp. 32-33 (1983). The Department has also found that senior advisory contracts must be shown specifically to be a recurring contract to be considered for the cost of service. *Fitchburg Gas and Electric Light Company*, D.T.E. 98-51, pp. 39-40 (1998) and *Bay State Gas Company*, D.P.U. 92-111, pp. 129-130. The Company included "incentive" payments made during the test year to the former chairman of Bay State Gas Company for some unspecified "consulting" work. Exh. AG-19-14. The payment and the work are derived from a termination contract signed with the Company during the NiSource merger. Exh. AG-11-14. The contract and the associated "incentive" pay ended during June 2005. Therefore, the Department should remove this "incentive" payment, since it is a nonrecurring non-extraordinary expense. *Fitchburg Gas and Electric Light Company*, D.P.U. 1270-1414, pp. 32-33 (1983).

3. LEGAL RETAINER

During the test year, the NCSC paid $720,000 to an Illinois law firm, Schiff, Hardin &Waite ("Schiff Hardin"), for legal services rendered by attorney Peter Fazio. Exh. AG-1-93. The Company has included $62,238 in the cost of service as its allocated portion of those legal service fees. Exh. AG-1-93, attachment, p. 1. Mr. Fazio is a partner of Schiff Hardin and also serves as the NCSC executive vice-president and general counsel. Exh. AG-1-98(A), Attachment p. 1 of 29; Tr. 9, pp. 1591-1592.[38] This relationship "raises a 'conflict of interest" concern because a partner of the firm rendering legal counsel to [Bay State] is also an [employee of NCSC]." *Cambridge Electric Light Company*, D.P.U. 92-250, p. 123-130 (1993).

The Department should remove these allocated fees because the Company has failed to justify their inclusion in the cost of service. Schiff Hardin is an outside law firm, and the Department requires outside legal fees to be known and measurable, reasonable and cost-effective. *Boston Gas*, D.T.E. 03-40, pp. 153, 157. Invoices supporting outside legal fees must contain the number of hours billed, the billing rate, and the specific nature of services performed. *Id.*, p. 157; *Fitchburg,* D.T.E. 02-24/25, pp. 193-194. The Schiff Hardin invoices are devoid of any detail except the month for which the services apply. Exh. AG-1-93, Attachment, pp. 2-5.

The Department should closely scrutinize legal fees and expenses charged to Bay State by a NiSource officer who is, consequently, serving two roles -- legal adviser and corporate officer. Department precedent requires companies to procure outside legal services based on a competitive bidding process unless the Company shows that their choice of outside counsel is both reasonable and cost effective. *Boston Gas*, D.T.E. 03-40, pp. 148, 153. The Company

[38] Mr. Fazio is listed in the Schiff Hardin web page, www.schiffhardin.com, as partner, chairman and executive committee member of the 340-attorney firm.

failed to obtain competitive bids for these outside legal services and has not demonstrated that its failure to bid the legal counsel fees was a reasonable and prudent decision and free of bias.[39] Exh. AG-19-36; Tr. 9, p. 1592. The Company has not shown that it has attempted to contain these legal costs. Although the Company agreed to supplement the record with copies of all bills for outside legal services for the past three years, it has not provided invoices that adequately support the legal fees that NCSC paid to Schiff Hardin. Exh. AG-1-95. These legal fees are not known and measurable and, therefore, the Department should remove $62,238 from the cost of service for the allocated portion of these legal retainer services. The Department should also remove all officer expenses associated with Mr. Fazio unless the expenses are itemized and directly assignable to work performed for Bay State Gas.

4. UNCOLLECTIBLE EXPENSE

The Company proposes to continue its current bad debt expense recovery mechanisms for both the distribution base rate and the CGA components as approved by the Department in its last rate setting settlement, *Bay State Gas Company*, D.T.E. 97-97. Although Bay State calculated the base rate bad debt allowance in a manner consistent with current Department precedent as defined in *Boston Gas Company*, D.T.E. 03-40, the component relating to the CGA does not comply with current precedent and, therefore, the Department should reject the CGA component.

According to Mr. Skirtich, the average of the test year and the two prior year's net write-offs was determined to be 2.15%. BSG/JES-1, Sch. JES-9 (August 2, 2005). This percentage

[39] The Department's policies in regard to legal fees are designed to prevent the "potential for self-dealing." Cambridge Electric Light Company, D.P.U. 92-250, p. 130, n. 55. Only following established precedent will alleviate this concern. *Id*.

was multiplied by the test year revenues and by the proposed revenue increase to determine the bad debt allowance. Exh. BSG/JES-1, Sch. JES-6, p. 9. Mr. Skirtich calculated a second component to increase the allowance to include costs related to the proposed revenue increase. Exh. BSG/JES-1, Sch. JES-5, line 3. This methodology, however, is not consistent with the Department's decision in the recent Fitchburg Gas and Electric and Boston Gas Company rate cases. *Boston Gas Company*, DTE 03-40, p. 267 (2003); *Fitchburg Gas and Electric Company*, D.T.E. 02-24/25, p. 172.

Part of the Company's rate design proposal is to collect the distribution portion of the bad debt allowance through the proposed base rates and the gas related portion through the CGA. This unbundling or separation of the recovery of bad debt allowance is consistent with current Department precedent. *Boston Gas Company*, D.T.E. 03-40, p. 267 (2003); *Fitchburg Gas & Electric Light Company*, D.T.E. 02-24/25 p. 171; D.T.E. 01-56, p. 96; *Boston Gas Company*, D.P.U, 96-50(Phase I) (1996), p. 72-73. The Company first unbundled its recovery of bad debt allowance in D.T.E. 97-97, a rate making settlement. In accordance with the D.T.E. 97-97 settlement and D.T.E. 96-50 (Phase I), Bay State began to recover through its CGA the amount of net write offs related to CGA costs. Although the CGA was estimated , it was reconciled to actual net write offs. According to the Company, it currently recovers dollar for dollar its gas related bad debt costs through its CGA. Tr. 6, pp. 1011-1012; Tr. 3, pp. 629-630; Exh. AG-22-12.

In DTE 02-24/25, the Department changed its position on the recovery of bad debt through the CGA.[40] It indicated that it was not the Department's policy to allow dollar for dollar recovery of production related gas costs through the CGA and rejected Fitchburg's attempt to do so, stating that to allow "dollar for dollar recovery removes the incentive for the Company to reduce its bad debt expense." *Id.* at 172. The Department then established its new policy when it directed Fitchburg

> "to apply each year's allocation factor to the level of bad debt expense approved in this rate case. By using this method, the Company shall not recover more than the level of bad debt expense approved in this case. We adopt this method because it preserves a company's incentive to reduce bad debt expense, while appropriately accounting for any migration to the competitive market."

Id. (fn eliminated). The Department reiterated this methodology in D.T.E. 03-40, when it required Boston Gas to comply with the D.T.E. 02-24/25 precedent. The Department again affirmed that the precedent "...preserves a company's incentive to reduce bad debt expense." *Boston Gas Company*, DTE 03-40, p. 267 (2003).

The Company has not provided any basis for the Department to depart from the precedent established in D.T.E. 02-24/25 and D.T.E. 03-40. In fact, it seems that the Company has simply disregarded the Fitchburg and Boston Gas cases; Mr. Bryant testified during the evidentiary hearings that the Company did not interpret the Department's decisions in D.T.E. 02-24/25 and D.T.E. 03-40 as binding precedent. Tr. 6, p. 1013. Mr. Bryant explained that the

[40] The Department's earlier precedent was based on the concern that recent developments in the competitive environment would result in migration from CGA gas sales service to competitive supply. *Boston Gas Company*, DPU 96-50 C, p. 30 (1997). This migration would affect the CGA costs and thereby reduce bad debt costs for this component. The Department addressed this concern by approving an allocation of bad debt costs between base rate related costs and CGA related costs. *Id.*, p. 34. The CGA component was expected to decrease over time as customers migrated to competitive suppliers.

Company's proposal is simply a continuation of the Company's current collection practices established in 1997, and confirmed that the collection practices are "different that what was granted to KeySpan, and the Company feels that its proposal is superior to that methodology which KeySpan is exposed to." *Id.*[41] Mr. Bryant explained that the Boston Gas methodology "would cause the company to fall significantly short of collecting its gas-cost-related bad debt" (Tr. 6, p. 1011) because it does not allow the collection of "actual bad debt experience" (i.e. dollar for dollar recovery) through the CGA. According to Mr. Bryant, without dollar for dollar recovery through the CGA, the Company would remain vulnerable to increasing bad debt related to the volatile commodity cost of gas. *Id.* at 1011-1012. The Department has previously considered this rationale, and its current policy and precedent do not permit dollar for dollar recovery of bad debt costs because such a policy would not provide adequate incentives to encourage utility companies to make diligent bad debt collection efforts.[42]

The Company's proposal relating to the collection of bad debt through the CGA clearly deviates from Department precedent established in D.T.E. 02-24/25 and D.T.E. 03-40. The Company failed to produce any substantial evidence or perform any studies supporting deviation from current precedent, and did not make any attempts to quantify the risk it claims it would if the Department instructed it to follow the bad debt recovery methodology established in D.T.E. 03-40. Tr. 6, pp. 1084-1087.

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[41]It is not clear from the record, however, that the Company, prior to filing this case, actually endeavored to analyze the KeySpan methodology and compare it to its own proposal. Tr. 6, p. 1010.

[42]Mr. Bryant assured the Department, however, that the bad debt component that "remains in the base rates causes the Company to have an incentive to be diligent and all that it can to collect bad debt." Tr. 6, p. 1012. However, given that only 30 percent of Bay State's bad debts are related to base rates, while the remaining 70 percent would be recovered under the Company's proposal on a dollar for dollar basis through the CGA, the incentive to recover base rate bad debt appears weak at best.

The Department should order Bay State to comply with the precedent established in D.T.E. 02-24/25 and D.T.E. 03-40. Allowing the Company to continue its current method of bad debt collection through the CGA, would not only diminish the Company's incentives to be diligent in its collection of bad debt.

5. ENERGY PRODUCTS AND SERVICES ("EP&S")

a. All benefits of EP&S Business Should flow to Distribution Customers Equitably

The Company operates several lines of business that are not rate regulated by the Department. These businesses include Guardian Care Services (maintenance of service contracts), Water Heater Rental, Fee for Service business and boiler and heating equipment installation business. Exh. BSG/SHB-1, pp.55-56. In 1999 the Department denied the Company's "...proposal to retain its service business integrated within its corporate structure and utility distribution operation." RR-AG-37, Letter to Mr. Richard P. Cencini, dated October 20, 1999. The Department later reversed its decision based on the Company's assurance that it would track costs associated with its service business on a fully allocated basis and ". . . would ensure that Bay State's service business activities are not subsidized by ratepayers and compete fairly with independent contractors in this regard." RR-AG-37, Letter to the Commissioners dated April 14, 2000; Exh. DTE-5-30.

The Company now proposes to include the costs and revenues from certain non-rate regulated operations in the cost of service. Revenues and expenses for the Company's all but the boiler and furnace installation business are considered above the line and are included in the Company's proposed revenue requirements. *Id.*, p.58. According to the Company, the EPS operations during the test year generated positive margins of $5.7 million, of which $4.9 million is included in the Company's proposed revenue requirement. Exh. MOC-4-2.

In its Allocated Cost of Service Study the Company allocates the above the line EP&S revenues, certain direct costs, and related investments (rental equipment and related depreciation) to each of the Company's rate classes based on the DISTR allocation factor which is the distribution demand based allocator used primarily to allocate Distribution Plant. AG-22-10, p. 2. The DISTR allocator allocates approximately 55% of the margin from the above the line EP&S to the residential classes. Exh. Sch. JLH-2-2, p. 51 of 92, lines 11 and 12, and p. 70 of 92, Distribution Allocators, line 1. The EP&S customers are overwhelmingly residential customers (only $11,700 of the $7.7 million Guardian Care revenue and only 16 of the more than 11,000 customers leasing conversion burners are commercial customers). RR-AG-61. The Company's residential customers also contribute the majority of the Company's earnings. Exh. BSG/JLH-2, Sched. JLH-2-2, p. 1 of 92, line 23. The Department has based class revenue requirements and cost allocations on cost causation principals. *Boston Gas Company*, DTE 03-40, p. 366 (2003) D.P.U. 93-60, pp. 345-346. The EP&S revenue should benefit the customers that generate the revenue and should be directly assigned to the residential class.[43] To do otherwise would have the residential class contributing to the same cost recovery twice. The result is inequitable and conflicts with the Department's fairness principals.

b. All Known and Measurable EP&S Revenue Increases Should Reduce the Revenue Requirement

[43] D.P.U. 93-60, pp. 345-346: The Department requires direct assignment of costs when expenses attributable to each customer class are readily and accurately measurable. *Commonwealth Electric Company*, D.P.U. 90-331, p. 243 (1991); *Boston Gas Company*, D.P.U. 90-17/18/55, p. 29 (1990); *Massachusetts Electric Company*, D.P.U. 89-194/195, p. 210-212 (1990); *Cambridge Electric Light*, D.P.U. 89-109, p. 44-47 (1989).

Although Bay State proposes to increase its prices to utility customers based on higher costs, it does not attempt to show how the cost increases affect the EP&S margins. Nor does the Company show the EP&S return on rate base on either a pro-forma basis or actual test year basis or allocate any capital investment or working capital needs to the EP&S business. Without this analysis the Department cannot determine if the utility customers are subsidizing the EP&S operation. Although the Company has assured the Department that it would track EP&S costs and revenues on a fully allocated basis, it has not. Absent evidence to the contrary, it appears that the full benefit of EP&S increases will accrue to shareholders while the utility customers cover all costs associated with the EP&S business through the rates approved in this case.

The Company increased fees and charges for several products and services during the test year and in 2005. RR-AG-56. The Company has not adjusted its test year revenue to account for these known increases. Department precedent requires that known and measurable changes to test year data be included in revenue requirements. The Company asserts that the test year volumes and customer counts are not representative of future levels. The assertion is purely speculative and lacks any evidentiary support. There is evidence that the EP&S rates will be increased by $794,259. *Id.*, p. 2. The Company's revenue requirement should be reduced by this amount to provide the benefits promised and lessen the magnitude of any subsidy provided by captive utility customers.[44]

c. Bad Debt Allowance for EP&S

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[44] It should be noted that the Company is free to increase the EP&S fees and charges at any time. Unlike the regulated rates the Department does not require its prior approval of rate increases to non-utility services. The revenue increases to EP&S fees and charges after this rate proceeding will benefit shareholders and not customers, while the costs to provide these services will be included in the Company's regulated rates that will be subjected to annual PBR increases.

In addition to the rate regulated, distribution service business related bad debt expense allowance, the Company also calculates an allowance for the EP&S business lines. The same approach as is used to determine the rate regulated allowance is used to determine the proposed allowance for the EP&S businesses. The average write off for the years 2002, 2003 and 2004 is 4.15%which results in a proposed increase to the Company's cost of service of $246,232. The rate is almost twice the rate of the net write offs for the regulated operations. The Company has not shown this rate to be just and reasonable or the result of prudent actions. As discussed infra, the Attorney General recommends that the Department mitigate the utility customers' cost burden related to EP&S –the Company has the ability to raise the rates and fees it charges for these services and has the obligation to insure that these lines, as long as the costs are commingled with the costs charged to the tariffed utility customers, are earning a fair return and are not subsidized in any way by the utility service customers. The Department should reject the EP&S bad debt adjustment and reduce the cost of service by $246,232.

6. THE COMPANY FAILED TO EXCLUDE ELECTRIC-TO-GAS CONVERSION PROMOTIONAL EXPENSES AND DID NOT PROVE THAT ITS SALES PROMOTIONAL EXPENSES BENEFITTED RATEPAYERS.

The Company included $1,136,100 in indirect sales promotional expenses and $240,545 in direct sales promotional expenses in its test year cost of service. RR-AG-30; Exh. MOC-1-1; Exh. MOC-1-3. Indirect sales promotional expenses include labor, materials and supplies, outside services, rents or leases, employee expenses, company memberships, utilities, and miscellaneous expenses. RR-AG-30; Tr. 5, pp. 825-828. Direct sales promotional expenses include advertising and marketing expenses. Exh. MOC-1-3; RR-AG-32.[45] The amount of direct promotional expenses in rates currently is $471,355, and the Company intends to spend $491,500 in 2005 for direct promotional expenses. Exh. AG-1-2(8), Bay State Gas 2004 Annual Return to the Department, p. 47, Accounts 911 - 916; Exh. MOC-1-1; Exh. MOC-1-2; Tr. 5, p. 841. The Department should exclude from the cost of service all $1,376,645 in sales promotional expenses because the Company failed to remove the sales promotion costs associated with conversions from electricity to gas, failed to conduct a cost/benefit analysis of the promotional programs or prove that the promotional expenses were prudently incurred, and failed to prove that the $1.3 million was a reasonable expense. *Boston Gas*, D.T.E. 03-40, pp. 247, 249.[46]

The Company did not track or remove the sales promotion expenses associated with the 844 residential, commercial and industrial conversions from electricity to gas. RR-AG-36; Tr. 6, pp. 960-964. During 2004, the Company acquired 3,317 new customers. Exh. AG-6-14. The Company provided the total number of conversions but claimed it could not provide the breakout

[45] The amount of advertisements included in the Company's test year cost of service is $200,871. RR-AG-32. All of the advertising invoices are promotional in nature and are ambiguous because they do not specifically reflect activities that benefit Massachusetts ratepayers. Boston Gas, D.T.E. 03-40, p. 287. The Company was unable to explain the reasons for several expenses such as the "Mea Culpa" letters (p. 17 of 21) and the purpose of sponsorship (p. 15 of 21). Bay State, furthermore, is paying more than its share of advertising expense. The allocated portion of the advertising invoices for Northern Utilities, Bay State's affiliate, appears to be approximately 8 %, even though the ratio of brochures produce for Northern customers compared to the total amount was 13% (14.5M / (92.25M + 14.5M). RR-AG-32, p. 5 of 21; Exh. MOC-1-3; Tr. 5, p. 848.

[46] The Department clearly warned all post-*Boston Gas* rate case applicants: "In future rate cases, all companies must present an IRR analysis that (1) excludes extraneous factors, such as growth-related capital projects; (2) is conducted program-by-program; (3) includes all indirect promotional expenses; and (4) is conducted on both a pre and post-implementation basis." *Boston Gas,* D.T.E. 03-40, p. 249.

of electric-to-gas versus oil-to-gas: "The Company tracks the number of conversions in total, but does not track the number from each individual alternative fuel." RR-AG-36.

Pursuant to G.L. c. 164, § 33A, the Department requires utilities to exclude from the cost of service those sales promotion expenses that encourage ratepayers to switch from one Department-regulated industry (*e.g.* electricity) to another.[47] *Boston Gas,* D.T.E. 03-40, p. 252; *Berkshire Gas Company*, D.P.U. 90-121, pp. 133-134 (1990). As a result of its failure to separately track electric versus heating oil conversion, the Department is unable to determine which sales promotional expenses are recoverable. The Company has failed to meet its burden of proof and, accordingly, the Department should exclude all sales promotion expense from the cost of service related to these 844 conversions.

To recover promotional expenses as part of the Company's base rates, the Company should have demonstrated that the programs resulted in net benefits to the rate payers. *Boston Gas*, D.T.E. 03-40, pp. 243-244. This analysis should occur before the programs were implemented, not afterward. *Id.,* p. 247 ("Hindsight IRR analyses are contrary to the very purpose of cost-benefit analyses, which is to assist in the decision on whether to embark on a project in the first place"). Above-the-line expenses must be justified using an incremental approach, whereas below-the-line expense justification requires that a portion of the indirect costs be assigned to the program. *Id.* at 243. Both net benefit analyses must include direct and

[47] "No gas or electric company regulated by the department under this chapter may recover from any ratepayer of such company any direct or indirect expenditure by such company for promotional or political advertising as defined in this section."

"For the purposes of this section, the following words and phrases shall have the following meanings: 'Promotional advertising', any advertising for the purpose of encouraging any person to select or use the service or additional service of a utility regulated by the department, or the selection or installation of any appliance or equipment designed to use such utility's service." G.L. c. 164, § 33A.

indirect costs. *Id.* When asked whether the Company conducted an incremental net benefit analysis for the sales promotional programs prior to their implementation, the Company could not specifically identify or produce such an analysis. Tr. 5, p. 833. Nor could the Company point to any internal rates of return analyses for its sales promotion programs, which should have included all indirect promotional expenses. Tr. 5, p. 835; *Boston Gas,* D.T.E. 03-40, p. 247. The Company failed to produce its analysis of the cost of adding additional customers to the system, another Departmental requirement to include promotional expenses in the test year cost of service. Tr. 5, p. 835. For these reasons the Department should exclude all sales promotional expenses from the cost of service.

7. THE COMPANY'S PROPOSED INCREASE IN NISOURCE CORPORATE SERVICES COMPANY'S EMPLOYEE MEDICAL COSTS IS NOT KNOWN AND MEASURABLE

The Department should deny the Company's proposed $274,566 increase to medical and dental costs for NiSource Corporate Service Company employees, since it is not known and measurable. Exh. BSG/JES-1, Sch. 6, p. 11. The Department's precedent regarding pro forma adjustments to the cost of service is well-established. *Fitchburg Gas & Electric Light Company*, D.T.E. 02-24/25, p. 76, 195 (2002), *citing Eastern Edison Company*, D.P.U. 1580, pp. 13-17 (1984). In determining the propriety of rates for the companies under its jurisdiction, the Department has consistently based allowed rates on test year data, adjusted for known and measurable changes. *Id.*

The Company's proposed increase for NCSC employees' medical and dental costs is simply set to equal the rate of increase for Bay State Gas Company's Massachusetts employees. Exh. BSG/JES-1, Sch. JES-6, p. 11 and WP-JES-6, p. 26, lines 14-19 (using Bay State Gas

Company's 22.30 percent calculated increase on line 19, as the pro forma increase for NCSC on lin 14). The rate of increase for the NCSC employees, who reside mostly in Indiana, will not be the same as Bay State employees in Massachusetts. First, the providers are different, since the Bay State Gas Company employees are all served by Massachusetts providers. Exh. BSG/JES-1, Sch. JES-6, p. 4. Second, like labor costs, there are different rates of increase in health care costs. *Compare* 2005 Bay State Non-Union salary increase of 2.21 percent and 2005 NCSC salary increase of 1.9 percent Exh. BSG/JES-1, WP JES-6, p. 3, line 11 (BSG) with p. 24, line 8 (NCSC). Finally, there are also different mixtures of coverage -- family versus single employee versus employee and spouse coverage that will cause the increase in insurance rates to be different. Exh. BSG/JES-1, WP-JES-6, pp.11-16. The Company provided no evidence to support its conclusion that the rate of increase for the NCSC employees is the same as for Bay State employees, and indeed, provided no evidence that there would be any increase in NCSC health care costs at all. Therefore, the Department should deny the Company's proposed $274,566 increase in medical and dental costs for its NCSC employees since it is not known and measurable. *Fitchburg Gas & Electric Light Company*, D.T.E. 02-24/25, p. 76, 195 (2002).

8. THE COMPANY FAILED TO CAPITALIZE ANY OF ITS WORKERS COMPENSATION INSURANCE COSTS

The Department should reduce the cost of service to reflect the capitalization of the Company's pro forma Workers Compensation Insurance Costs. The Company proposes to include the total cost of its pro forma Workers Compensation Insurance premium in base rates. Tr. 21, p. 3547, and Exh. BSG/JES-1, Sch. 6, p. 5, line 3. Workers Compensation Insurance is a cost of employing labor in Massachusetts. Tr. 21, p. 3547. The Company includes the total $673,516 insurance premium in its pro forma costs of service in this case. *Id*.

The Company failed to allocate any of its Workers Compensation Insurance cost to its construction activities. *Id*. Since Workers Compensation is a cost of labor, it should be allocated like all costs of labor to its construction activities. *See e.g.*, Exh. BSG/JES-1, Sch. 6, p. 4, line 36 (Medical and Dental costs) and Exh. BSG/JES-4, lines 3 and 15 (Pension and PBOPs costs). Like the other labor cost adjustments, the Department should follow that share of wages and salaries allocated to construction to determine the amount of Workers Compensation to allocate. During the test year, the Company allocated 24.36 percent of its labor costs to construction. *Id*. Therefore, the Department should reduce the cost of service by $164,069 [$673,516 x 0.2436] to reflect the allocation of Workers Compensation to construction.

9. THE COMPANY FAILED TO REMOVE CAPITAL COSTS FROM ITS RESIDUAL OPERATIONS AND MAINTENANCE EXPENSE

The Company failed to remove certain capital costs from the residual operations and maintenance expense balance used to determine its inflation adjustment. During the test year, NCSC charged the Company over $24 million in costs. Exh. BSG/JES-1, WP JES-6, p. 28, lin 13. These NCSC costs, including capital costs such as depreciation, income tax, interest costs, and property taxes, were charged to operations and maintenance expense account 923, totaling $762,423 ($495,072 + $(89,258) + $76,650 + $279,959). Exh. AG-1-25. It included similar costs allocated from Northern Utilities in Account 931, totaling $190,868 ($90,138 + $26,757 + $9,226 + $64,747). *Id*. Finally, the Company included property taxes associated with its Westborough building in Account 931 in the amount of $71,788. *Id*. These accounts are included in the Company's proposed balance of operations and maintenance expense subject to its inflation adjustment. *Id*. and Exh. BSG/JES-1, Sch. JES-6, p. 19. Since the capital costs are fixed and will not increase with the inflation in the economy, they should be eliminated from the residual operations and maintenance expense balance. *See, e.g., Bay State Gas Company*, D.P.U. 92-111, p. 163 (removing property taxes on leased LNG tanks)*; Western Massachusetts Electric Company,* D.P.U. 84-25, p. 85 (1984) (removing service company carrying charges); *Commonwealth Electric Company,* D.P.U. 956, p. 38 (1982) (removing fixed costs not subject to inflation); *Boston Edison Company*, D.P.U. 906, pp. 71-74 (1982).

10. THE DEPARTMENT SHOULD DENY THE COMPANY'S PROPOSED ADJUSTMENTS TO ITS DEFICIENCY IN ACCUMULATED DEFERRED INCOME TAXES

The Company proposes to increase its amortization of the deficiency of deferred income taxes to make changes to the balances being amortized. Exh. BSG/JES-1, WP JES-11, p. 1. In its base rate case D.P.U. 92-111, the Company asked collect $4,385,240 of deficiency over 25.2 years through base rates. *Id*. Here, the Company proposes to increase the balance being recovered to recover amounts that it did not seek recovery for in D.P.U. 92-111.

The Company should have followed Generally Accepted Accounting Principles ("GAAP") in the recognition and the amortization of any additional deficiency in deferred income taxes at the time it was known, instead of deferring recognition until a base rate case, as the Company did. Exh. AG-9, pp. 20-21. In the same way the Company does not defer recognition of depreciation expense when plant goes into service or defer revenue when new customers come on the system, the Company should not be allowed to defer costs, waiting until base rate cases to recognize those costs. *Id.* If the Company had begun the amortization of the added deficiency during 1993, the annual amortization would have been reduced by $43,000. Exh. AG-9, p. 21 and Sch. DJE-4. Therefore, the Department should deny the Company's proposed adjustments to its deficiency in accumulated deferred income taxes and reduce the cost of service by $43,000. *Id.*

11. Corporate Jet Expenses Are Imprudent.

The Company included $150,444.61 in the test year cost of service as its allocated portion of expense derived from the use of a Raytheon Hawker 800 XP jet, for which NCSC paid over $12.5 million . Tr. 9, pp. 1550, 1552; AG-1-54; AG-19-27. The Company used this jet to attend various corporate meetings. RR-AG-45, RR-AG-46. The NCSC's annual jet expense, therefore, is roughly $2.1 million based on an allocation of 7% to Bay State. RR-AG-45.

The Company has not demonstrated that the use of this aircraft to that extent has provided any benefit to the ratepayers, or that the Company has attempted to contain costs by, for example, providing a cost comparison of the flights taken using the private jet versus public airlines. While a private jet may provide more convenience at times, that convenience comes at a price which may far exceed its public counterpart. Without that cost comparison, or similar demonstration of the Company's cost-containment effort, the Department cannot evaluate whether the cost was reasonably and prudently incurred. Accordingly, the Department should remove Bay State's allocated jet expense, $150,444.61, from the test year cost of service.

12. Penalties and Late Fees Should Be Excluded.

According to Department records, the Company paid at least $6,500 in Dig-Safe fines to the Department's Pipeline Engineering and Safety Division during the test year. Exh. AG-4. The Company did not adjust its operating expenses for Dig-Safe fines and penalties paid during the test year, as other companies have. See, e.g., *Boston Gas,* D.T.E. 03-40, p. 258. Rather, the Company asserted that these fines were booked "below the line" and therefore not included in the test year cost of service. Exh. AG-1-83 (Supp.); Tr. 5, pp. 814-815. The Company asserted that it generally books fines below the line but admitted that it does not keep separate records for penalties incurred by separate subsidiaries. *Id.*

The Department excludes Dig-Safe fines from the cost of service as a matter of public policy. *Boston Gas Company*, D.P.U. 96-50 (Phase I), p. 110 (December 2, 1996); D.P.U. 88-67, Phase I, p. 43 (1988); *Kings Grant Water Company*, D.P.U. 87-228, pp. 18-19 (1988); *Nantucket Electric Company*, D.P.U. 1530, p. 26 (1983). Because the Company did not specifically adjust the test year to remove the fines, the Company has not substantiated its claim. Therefore, the Department should remove the Dig Safe fines from the cost of service to ensure that ratepayers are not paying for the Company's violations. The Department also should require the Company to set up separate Dig Safe accounts in the future to track and correct this accounting problem.

For the same reasons, the Department should ensure the Company records and excludes from the test year cost of service all payments for judgments, settlements, late fees and consumer conversion fees. The Company included $250,310 in the test year cost of service for settlements and judgments paid to individuals arising from the Company's operations. RR-AG-25. The Company has not demonstrated that those payments benefitted ratepayers collectively, so the amounts should be removed from the cost of service. The Company admitted that it had inadvertently included late fees for lease-type expenses in its cost of service as part of Exh. AG-1-64. Tr.21, pp. 3505-3506. Examples (but not a complete listing) of those late fees are included in AG Exh. 10. Additional late fees (labeled as "interest") are found in Exh. AG-3-17 (invoices from Coler and Colantonio for blue prints and square footage measurements of the

Company's offices, in mylar and Adobe Acrobat (.pdf) format). The Department should exclude all late fees included in the cost of service, including those reflected in Exh. AG-1-64 and Exh. AG-3-17.

The Company included expenses in its cost of service for conversion guarantee fees -- penalties, of a sort, for the Company's inability to make its appointments for service conversions.[48] The Company also refunded nearly $14,000 to customers in 2004 for telephone line repairs associated with the installation and removal of Metscan devices. Exh. AG-21-3 (revised). These refunds serve the same purpose as Dig-Safe penalties since customer refunds provided the Company with an incentive to replace the defective Metscan devices. The Company has not demonstrated that these fees were not included in the cost of service, so the Department may reasonably assume, absent contrary proof, that the base rate calculation includes these fees. The Department should, therefore, remove those expenses from the cost of service to ensure that ratepayers do not pay the Company's penalties and to provide the Company with additional incentive to track by subsidiary and demonstrably remove all penalties and late fees.

13. BAY STATE OVERSTATES ITS RATE CASE EXPENSES

The Company has included $1,410,950.72 in the test year cost of service as rate case expenses to date and, as of August 9, 2005, estimates that the Company will spend another $503,434.54, for a grand total of nearly $2 million. Exh. DTE-15-58 (Supp. 3). The Department allows recovery for rate case expenses if the expenses are known and measurable. *Berkshire*

[48] Customer guarantee payments for failure to keep service appointments are regularly excluded from the cost of service. As the Department found: "There is neither logic nor justice in the Company's asking to pass on its penalty to all ratepayers collectively." *Boston Gas,* D.T.E. 03-40, p. 261-262.

Gas, D.T.E. 01-56, at 75; *Dedham Water Company*, D.P.U. 84-32, at 17 (1984). The Department should exclude a number of these expenses because the Company has failed to demonstrate that ratepayers will benefit from the expenses and failed to put out several of the outside services to competitive bid. *See* Exh. DTE-15-56.

For example, the Company included expenses for rate case services from Hewitt Associates, a company which Bay State retains on contract to provide year-round payroll and benefit services. See, e.g., Exh. AG-3-13; Exh. DTE-15-58. These expenses do not belong in the rate case because the Company pays Hewitt $6.5 million annually to perform most if not all of the services any way. The Company did not present a Hewitt representative at hearings for cross-examination as to the reasonableness of the expenses. Tr. 8, pp. 1255-1257, 1276-1277. Hewitt's invoices include unspecified expenses that do not explain how ratepayers benefitted from Hewitt's services. *See, e.g.*, Exh. DTE 15-58 (Supp.3). Mr. Barkauskas testified that the Service Company approved Hewitt's pension and PBOP reports during a short meeting without further discussion of their merits. Tr. 8, pp. 1349-1350. Bay State did not set this rate case expense for competitive bidding for these outside services and did not present a Hewitt representative for examination at hearings. Tr. 8, p. 1294; Exh. DTE-15-56.

Bay State included expenses from R. J. Rudden for services that appear to relate to the Company's SIR program. See, e.g., Exh. DTE-15-58 (Supp. 2) Attachment (e). The Department should remove these expenses because the Company did not use the Rudden reports as support for its SIR program. The Company also included expenses from Yardley and Associates but failed to demonstrate that these services were not duplicated by charges assessed by Mr. Ferro.

See, e.g., Exh. DTE-15-58 (Supp. 1). The Company did not present a Yardley representative for cross-examination as to the reasonableness of these expenses.

The Company included expenses for services from Corporate Renaissance as a rate case expense. Tr. 21, pp. 3498-3500. This expense, however, reflects activity that is better attributed toward preparing the Company's annual service quality report, rather than the rate case. Tr. 21, pp. 3496-3500. Accordingly, the Department should remove these expenses from the rate expense portion of the cost of service.

The Company has included expenses for meals as a rate case expense. Exh. DTE-15-58; Tr. 21, p. 3501. Meal expenses, like all rate case expenses, cannot be included unless there is a demonstrable benefit to ratepayers. Furthermore, the Company has failed to demonstrate how it has attempted to contain these costs.[49] The Company has failed to demonstrate that benefit, so the Company should eliminate expenses from the cost of service reflecting meal expenses included as a rate case expense.

The Company included expenses in the test year cost of service as its allocated portion of fees for floorplans and blueprints prepared by Coler and Colantonio. Exh. AG-3-17; Tr. 21, pp. 3501-3502. These plans covered buildings owned in Massachusetts, Maine and New Hampshire. Tr. 21, p. 3502, yet Northern was not allocated any of the expense. Furthermore, Coler and Colantonio have not provided the Company with electronic versions (Adobe Acrobat) of the

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[49] The Department has cautioned companies that rate case expense, like any other expenditure, is an area where the companies must seek to contain costs. *Fitchburg,* D.T.E. 02-24/25, at 192; D.P.U. 96-50 (Phase I) at 79." *Boston Gas*, D.T.E. 03-40, at 147-148.

Westborough floorplans with square footages, as required under Coler's contract.[50] The Department should remove this expense from the cost of service.

The Company has included expenses for a Konica copy machine that appears to be leased by Bank of America Leasing. See, e.g., Exh. DTE-15-58 (Supp. 1). The Konica and Bank of America invoices reflect a potential double-billing for the copier's lease expenses. The Department should ensure that ratepayers pay only once for legitimate rate case expenses. Additionally, the Bank of America Leasing invoices include late fees which must be removed from the rates.

14. THE DEPARTMENT SHOULD ELIMINATE THE AMORTIZATION OF THE METSCAN COSTS FROM THE COMPANY'S REVENUE REQUIREMENT

The Company proposes to continue collecting costs associated with a redundant, unused asset that is not in service and therefore not providing any benefits to ratepayers. To allow the Company to recover these costs, would violate Department precedent. *Fitchburg Gas and Electric Company*, D.T.E. 98-51, p.9. Accordingly, the amortization of the Metscan costs should be eliminated from the Company's revenue requirement, and the Department should reduce the Company's revenue requirement by $2,702,000. Exh. DJE-3.

It is well established that "for plant costs to be included in rate base, the expenditures must be prudently incurred, and the resulting plant must be used and useful in providing service to ratepayers. *Fitchburg Gas and Electric Company*, D.T.E. 98-51, at 9; *Boston Gas Company*, D.P.U. 96-50 (Phase I) at 15; *Boston Gas Company*, D.P.U. 93-60, at 42 (1993); *Western Massachusetts Electric Company*, D.P.U. 85-270, at 60-107. The Department considers plant to

[50] If Coler has, indeed, provided those electronic floorplans to the Company, then the Company is under an obligation to provide them to the Department and Attorney General. Exh. AG-3-42.

be 'used and useful' if the plant is in service and provides benefits to customers. D.T.E. 98-51, at 9; D.P.U. 96-50 (Phase I) at 15. In the absence of extraordinary circumstances, the Department normally does not allow the re-litigation of the used or usefulness of plant once it has been included in rate base." D.T.E. 02-24/25, at 22, *citing* D.P.U. 93-60, at 43; D.P.U. 92-210-B at 14. *See also* D.T.E. 01-56, at 42. This standard holds true for all plant, including that which is leased. The Department has recently made clear that continuing to pay rent on property that provides no useful service to ratepayers fails to meet the used and useful standard for inclusion in rate base. D.T.E. 03-40 at p. 90-91, *citing* D.T.E. 01-56, at 42-43; D.P.U. 93-60, at 41-44. Finally, the used and useful standard does not extend to redundant plant. Redundant plant is plant that if it were to be used, would provide the same purpose as does the Company's already existing and functioning plant. The Department has clearly stated that redundant and unused plant does not benefit ratepayers and is not used and useful. D.T.E. 01-56, at 42-43.

Metscan is a telephone based, automated meter reading technology that was installed and in service to customers throughout the 1990s but has now been retired and replaced by a wireless meter reading system. Exh. BSG/SHB-1, p. 45; Tr.1 p.138-139. The device was installed on a gas meter and a wired connection between the customer's meter and the customer's telephone line. Exh. BSG/SHB-1, p. 46. Meter readings were then transmitted over the phone line to the Company's billing and customer information center. *Id.*

In 1996-1997, the Company became aware of the weather related reliability problems with the Metscan devices. Tr. 1 p.140. At that time, it became evident to the Company that devices that were installed on outside meters experience relatively high failure rates due to exposure to the elements. *Id.* In 1998, a point in time when the Company was clearly aware of device reliability and longevity problems, Bay State proceeded to enter into a series of sale and lease back agreements with Fleet Capital Leasing. Exh. DTE 1-20. The Company received a cash payment of $23,104,922.83 from Fleet, which was equal to the net book value of the equipment. Exh. RR AG-13; Exh. RR AG-14; Exh. RR AG-83. The cash payment had no impact on the rates paid by customers and there is no evidence on the record that the Company's customers directly benefitted from the multi-million dollar cash payment. Exh. RR AG-83. The operating leases with Fleet have lease terms of 11 years, despite the fact the by the time the Company entered into the lease agreement, it was well aware that device reliability problems were likely to occur after the device had been in service for 7 years. Exh. DTE 1-20; Exh. AG 3-33.

In 2000, the Company decided, without issuing an RFP to determine other available technologies, to upgrade to the Itron wireless meter reading system. Exh. BSG/SHB-1, p. 48; Exh. AG 21-22. This was particularly convenient for Bay State Itron had acquired the Metscan product line in the mid 1990s after Metscan had filed for bankruptcy. Exh. AG-3-32; Exh. AG-21-22.

The Company cannot say with certainty the number of devices in service at the end of the test year, nor can it state weather those devices in service at the end of the test year are reflected on the Company's books or covered under the Fleet operating leases that were executed in 1998. Tr.1 p. 146-148. In fact, as a matter of practice, the Company did not keep records of the number of Metscan devices that were installed each year. RR-DTE-49-SUPP. Despite it's uncertainty and indifference regarding the number of devices in place or whether they are leased or owned, the Company is seeking approval to amortize$13.2 million associated with the undepreciated plant investment and the expected net present value of lease payments associated with Metscan over 5 years. Exh. BSG/SHB-1, p. 45.

The Metscan devices are redundant and unused, and therefore fail to meet the Department's used and useful standard and should be excluded from rate base. D.T.E. 03-40, p 90-91. D.T.E. 01-56, at 42-43; D.P.U. 93-60, at 41-44. If the Department were to allow the Company to collect for the Metscan devices, it would be effectively allowing the Company to be engaging in a double collection of sorts. Ratepayers are paying twice for equipment that serves the same function. This is the very definition of redundant plant. D.T.E. 01-56, at 42-43.

Moreover, the costs associated with the Metscan devices continued to rise through the 1990s. These devices were not weatherized to function in New England winters and because of this malfunction, outside meters failed at a rate of 14%. Exh. AG-3-32(b) p. 13. In order to compensate for these failures, the Company incurred additional costs associated with replacement batteries and manual meter reads. Exh. AG-3-32. Further costs were incurred when customers telephone lines were damaged during the installation and removal of these devices by Company employees. Exh. AG-21-3. As a result, the Company paid out $43,825.24 in refunds to customers due to the damage caused, adding to the increasing costs of this program. *Id.* The costs associated with customer refunds were capitalized as part of the Itron installation. Exh. RR-AG-12.

Although the ratepayers were affected by the escalating costs of the Metscan system, they, unlike the Company's shareholders, did not enjoy the benefits of the Company's financial arrangements relating to the devices. For example, Bay State received a cash payment of over $23 million from Fleet, yet there seems to be no acknowledgment of this benefit to ratepayers.

As Mr. Effron stated in his prefiled testimony, “even if the proceeds were treated as salvage, this would mean, at a minimum, that the Company had a source of non-investor funds available that was never reflected in its revenue requirement during the rate freeze following D.T.E. 98-31. There has been no recognition of this benefit in the Company’s quantification of the remaining Metscan costs to be recovered.” Exh. DJE-1 at 19.

The Metscan devices are not in service and do not provide benefits to ratepayers, therefore they are not used and useful. The inclusion of the Metscan devices in the Company's rate base is inappropriate because the devices will not be in service when the rates approved in this proceeding are in effect. D.T.E. 02-24/25, at 23, *citing* D.P.U. 85-270, at 140-141. The Metscan devices fail to meet the Department’s used and useful standard for inclusion in rate base. D.T.E. 03-40, p 90-91. D.T.E. 01-56, at 42-43; D.P.U. 93-60, at 41-44. Accordingly, the Department should eliminate the $2,702,000 amortization of the Metscan from the Company’s revenue requirement. Exh. DJE-3.

15. THE COMPANY’S COST OF SERVICE SHOULD BE REDUCED TO REFLECT THE EXPENSE REDUCTIONS FROM NISOURCE CORPORATE SERVICE COMPANY’S NEW IBM SERVICE CONTRACT

The IBM contract with NiSource Corporate Services Company to outsource a significant amount of its functions provides a known and measurable reduction to Bay State Gas Company’s test year cost of service in this case. The Department’s precedent regarding pro forma adjustments to the cost of service is well-established. *Fitchburg Gas & Electric Light Company*, D.T.E. 02-24/25, p. 76, 195 (2002), *citing Eastern Edison Company*, D.P.U. 1580, pp. 13-17 (1984). In determining the propriety of rates for the companies under its jurisdiction, the

Department has consistently based allowed rates on test year data, adjusted for known and measurable changes. *Id*.

NiSource Corporate Services Company has signed a company defining long-term outsourcing contract with IBM (the "Contract") to turn over the operations and maintenance of large amounts of its functions to this outside services provider. Exh. AG-RR-9. The $1.5 billion Contract is for a term of ten years with the option to extend for another five years. *Id*., p. XX and Exh. DTE-18-1 (a), p. 4. It will turn over to IBM significant portions of the Service Company's functions, including human resources, meter to cash, finance & accounting, customer contract centers, supply chain, and information technology. Exh. RR-AG-10(a). NiSource announced in a Securities and Exchange Form 8-K that it will achieve savings upwards of $530 million over the contract's life.[51] Exh. DTE-18-1 (a), p. 4.

The Bay State Gas Company has failed to pass on any of the Service Company savings from the IBM contract to its customers in the pro forma cost of service. Tr. 3, pp. 524-525 and Exh. BSG/JES-1, Schedule JES-6, pp. 1 and 11. Rather, than reducing costs to reflect the IBM Contract, it increases the cost of service for Service Company employee payroll, benefits, and payroll taxes as well as increases for Service Company inflation that will never happen. Id., p. 11 and Exh. DTE-6-13. The Department must should not allow the Company's shareholders to unfairly gain at the expense of it customers by charging these phantom costs or those costs above those that reflect the IBM Contract savings.

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[51] The $530 million of contract savings NiSource and IBM reported in their press release appears to be an amount before the costs to achieve listed in the press release.

The IBM Contract for services creates a known and measurable reduction to the cost of service that should be recognized by the Department. The Contract is known, as it has been signed and has been in effect since July 1 of 2005. Exh. AG-RR-9. The contracted costs and savings are measurable, since they have been quantified, contracted for, and reported by NiSource and IBM to the financial community. Exh. DTE-81-1 (a). The cost savings associated with the IBM contract should be passed on to Bay State Gas customers as a known and measurable reduction to the cost of service. *Fitchburg Gas & Electric Light Company*, D.T.E. 02-24/25, p. 76, 195 (2002), *citing Eastern Edison Company*, D.P.U. 1580, pp. 13-17 (1984).

The net savings to customers that should be passed through to customers can be determined from the Company's response to Record Request AG-RR-10 and Exh. DTE-18-1 (b), p. 36. The Core Savings for the Service Company are $532.8 million. Exh. DTE-18-1 (b), p. 36. Based on the percent of Actual Billing to Bay State Gas Massachusetts for 2004 in each cost center, Bay State will achieve 8.95 percent of the Net Core Savings from the eight functional areas it uses. Exh. RR-AG-10(b) and Tr. 20, pp. 3197-3198. Applying this percent to the total Net Core Savings of $395.8 million (including those of the General Cost Center), Bay State can expect to achieve $35.42 million in cost savings from the IBM Contract [0.0895 x $395.8 million]. Exh. DTE-18-1 (b), p. 36. Recognizing this amount over the ten year contract results in annual savings of $3.54 millions. Exh. DTE-18-1 (a), p. 4. Since some of the costs will be capitalized, it is appropriate to reduce the savings by the 3.18% percent of the costs that will be capitalized and reduce the cost of service by the remaining amount – $3.43 million [$3.54 million x (1 - 0.0318)]. Tr. 21, pp. 3521-3524.

For all of the above reasons, the Department should reduce the Company's cost of service by $3.43 million to recognize the known and measurable decrease in the Service Company allocated costs as a result of the IBM contract as well as all of the pro forma adjustments to the cost of service for the Service Company for employee payroll, benefits, and payroll taxes and increases for Service Company inflation.[52] Id., p. 11 and Exh. DTE-6-13.

16. THE DEPARTMENT SHOULD INSURE THE COMPANY'S REQUESTED REVENUE REQUIREMENT REFLECTS THE WITHDRAWAL OF THE GTI FUNDING PROPOSAL.

The Company indicated during the proceedings that it was withdrawing its Gas Technology Institute ("GTI") funding proposal included in its initial filing. *See* Exh. BSG/DGC-1, pp. 58-63, Tr. 6, pp.1049-1050. The Company told the Department that it would correct the cost of service and issue the adjustment to the revenue requirement in its next set of updated schedules. Tr. 6, p. 1050. The updated schedules dated August 2, 2005 still included the money that had been added for the GTI funding proposal. *See* Exh. BSG/JES-1, Schedule JES-6, p. 1 of 20 Corrected, dated August 2, 2005. The Department should order the Company to refile its schedules so that no money that is part of the GTI funding proposal is included in the cost of service or the requested revenue requirement.

G. COST OF CAPITAL

[52] The Company may argue that the costs to achieve are front loaded and should be recognized as such, however, this argument fails. The Company will incur the costs to achieve in various amounts over the ten years of the contract in a manner related to the contract as a whole, rather than the activities associated with the ongoing operations of any particular year. Therefore, it is appropriate to allocate those costs to achieve over the ten-year term like any other cost of a contract. (See for instance bonds).

The cost of service includes a return on rate base component that provides investors of the Company with a return on the net investment that has been made in the assets used to provide local gas distribution service. Exh. BSG/JES-1, Sch. 1. The return compensates the debt holders, the preferred stockholders, and the common stockholders in the Company. *Id*., Sch. 13. The dollar amount of the return is determined by multiplying the dollar amount of rate base by the overall cost rate of these different cost of capital weighted by the amount of each outstanding. *Id*.

1. THE DEPARTMENT SHOULD INCLUDE SHORT-TERM DEBT IN THE COMPANY'S CAPITAL STRUCTURE SINCE THE COMPANY USES IT TO PERMANENTLY FINANCE ITS INVESTMENTS

The Department includes a return on investment in utility plant in the cost of service used to determine base rates. *Boston Gas Company*, D.T.E. 03-40, p. 319 (2003); and Exh. BSG-JES-1, Sch. JES-5. That return on that investment is based on the utility's overall weighted cost of capital ("WACC"), calculated by weighting the cost rate of each issue by the balance outstanding. *Boston Gas Company*, D.T.E. 03-40, p. 319 (2003). The Department generally uses the test year end balance of the outstanding issues of permanent capital including debt, preferred equity and common equity, adjusted for known and measurable changes to the debt issues. *Id*. The Department includes long-term debt *as well as short-term debt* in the capital structure when short-term debt is a significant component of the utility's finances. *Blackstone Gas Company*, D.T.E. 01-50, pp. 24-26 (2001); *Wylde Wood Water Works, Inc*., D.P.U. 86-93, p. 25 (1987). In reviewing and applying utility company capital structures, the Department seeks to protect ratepayers from the effect of excessive rates of return. *Blackstone Gas Company*, D.T.E. 01-50, p. 25 (2001); *Assabet Water Company*, D.P.U. 95-92, p. 33 (1995); *Wylde Wood Water*

Works, Inc., D.P.U. 86-93, p. 25 (1987); *Blackstone Gas Company*, D.P.U. 1135, p. 4 (1982). Given Bay State's level of short term debt, the Department should include the portion of short-term debt that the Company uses to finance its rate base in the overall cost of capital. Tr. 17, pp. 2833-2836, and Exh. BSG-AG-1-16.

The Company has maintained a large balance of short-term debt that is permanently financing the Company's investments. Tr. 17, pp. 2833-2836, and Exh. BSG-AG-1-16. The history of Bay State Gas Company's financing from short-term debt indicates that it has become a significant and growing portion of permanent financing for the Company. *See Annual Returns to the Department, p. 32.* Since NiSource acquired the Company, its short-term debt has been:

Balance of Short-Term Debt

1999	$116,800,000
2000	$138,000,000
2001	$140,250000
2002	$218,888,528
2003	$192,656,450
2004	$157,939,415

Bay State Gas Company Annual Returns to the Department, p. 32.

The average balance during the thirteen months from December 2003 through December of 2004 was $186,343,535 and the average interest rate for that period was 1.94%. Exh. RR-DTE-118.

The short-term debt balance does vary during the months of the year because it is used to finance rate base investment as well as the Company's seasonal gas purchases. Tr. 17, pp. 2833-

2836 and Exh. RR-DTE-118. Still, the average amount of capital required to finance these gas purchases is relatively small. Ex. RR-DTE-118. The amount of capital required for the gas purchases of $33,131,681 can be determined by multiplying the annual gas costs of $323,863,512 by the purchased gas working capital lead/lag factor of 37.34/365 from the Company's lead/lag study. Exh. BGS/JES-1, Sch. JES-1 and Exh. BGS/JES-2, Sch. WC-4. Therefore, the short-term debt principally used to finance rate base is $153,211,854 [$186,343,535 - $33,131,681], after deducting the capital required to finance gas purchases.

The $153,211,854 balance of short-term debt that is permanently financing Bay State Gas Company should be incorporated in the capital structure used to determine the Company's overall cost of capital. Tr. 17, pp. 2833-2836, and Exh. BSG-AG-1-16. It is both a significant and permanent source of financing for the Company. *Id.* Furthermore, short-term debt is a source of low-cost financing that should be included in the cost of capital so that the base rates set by the Department represent the true cost of service. *Id*. Failure to add short-term debt to the capital structure will allow the Company's shareholders to unfairly profit at the expense of its customers. Using Bay State's proposed cost of service, and capital structure, and simply adding short-term debt to the capital structure will reduce the Company's revenue requirement by more than $12 million. Exh. RR-DTE-118. Failure to include short term debt in the capital structure would result in an unfair transfer of wealth to shareholders. *Blackstone Gas Company*, D.T.E. 01-50, p. 25 (2001); *Assabet Water Company*, D.P.U. 95-92, p. 33 (1995); *Wylde Wood Water Works, Inc*., D.P.U. 86-93, p. 25 (1987); *Blackstone Gas Company*, D.P.U. 1135, p. 4 (1982). Therefore, the Department should include a balance of $153,211,854 in short-term debt at a cost rate of 1.94 percent in the Company's capital structure used to determine the cost of service.

2. Cost of Common Equity

a. Introduction

The determination of the cost of common equity is not readily measured like the cost of debt which normally has a stated contractual rate. The Attorney General sponsored the testimony of Mr. Timothy Newhard regarding the cost of common equity. Exh. AG-8. Mr. Newhard provided two market based cost of equity analyses based on a comparison group of gas companies. *Id*. He also provided checked his results by perform similar analyses to determine the cost of equity for NiSource, Bay State Gas Company's parent corporation. *Id*., p. 18. Since Bay State Gas does not issue common stock that is publicly held or traded, it is impossible to determine the market cost of equity for the Company's stock using any market based approach. *Id*., p. 4. Therefore, Mr. Newhard chose a group of companies that he deemed comparable in investment risk to Bay State Gas and performed his cost of equity analyses on this group of companies to determine the cost of equity for the Company. *Id*., pp. 5-6 and Sch. 1. As a result of his analyses in this case, Mr. Newhard determined that the cost of common equity for Bay State is 8.66 percent. *Id*., p. 18.

The Company also sponsored a cost of equity witness – Mr. Paul Moul. He performed four analyses that the Department has reviewed and rejected many times before. Mr. Moul's methodologies are fundamentally flawed and should be rejected by the Department. He has testified many times before this Department and it has summarily rejected his analyses and recommendations each time. *See e.g.*, *Boston Gas Company*, D.P.U. 03-40, pp. 356-361 (2003); *Berkshire Gas Company*, D.T.E. 01-56 (2001), pp. 104-106, 108-109, 113, and 116-119; *Boston Gas Company*, D.P.U. 96-50, pp. 119-121, 125, 128, and 131-132 (1996). While changing the companies that comprise his comparison group and updating the numbers, his analyses remain basically the same as those that the Department has repeatedly rejected. *Id*. As with those other cases, his cost of equity analyses, here again, grossly overstate the cost of capital for the barometer group and the Company. See discussion of Mr. Moul's analyses, *infra*. Therefore, the Department should once again reject this analyses and instead rely on the recommendations of set forth below and in Mr. Newhard's testimony. Exh. AG-8, p. 18. As is discussed below, using appropriate stock market-based analyses, and adjusting for Bay State Gas Company's lower investment risk, the Department should use a cost of common equity no higher than 8.66 percent to determine the Company's revenue requirement in this case. *Id*.

b. Standard of Review

The Department uses *Bluefield Waterworks and Improvement Co. v. Public Commission*, 262 U.S. 679, 692-695 (1923) and *Federal Power Commission v. Hope Natural Gas Company,* 320 U.S. 391 (1942) standards to provide some of the parameters that it uses to determine the cost of common equity for a utility. In the *Bluefield* decision, the Court found that a fair rate of return for a regulated utility should be:

- equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties;

- reasonably sufficient to assure confidence in the financial soundness of the utility;

- adequate, under efficient and economical management, to maintain and support its credit and allow it to raise the money necessary for the proper discharge of its public duties.

c. Mr. Newhard's Two Stock Market Based Analyses Of The Cost Of Equity

Mr. Newhard provided two stock market based approaches to estimate the cost of equity for Bay State Gas Company. *Id.* He also performed two similar analyses for NiSource as a check on his results from his Bay State analysis. *Id.*, p. 18. Each of these analyses will be discussed separately below.

i. Mr. Newhard's Constant Growth Rate Discounted Cash Flow Analysis

Mr. Newhard performed a DCF analysis on a group of companies that he deemed were comparable to the Company in investment risk. Exh. AG-8, pp. 4-7. The economic theory underlying the application of the DCF analysis is that the market price that an investor is willing to pay for a share of common stock is equal to the present value of the cash dividends and the proceeds from the sale of the investment when the investor sells the stock. *Id.* Appendix A. The DCF theory can be modeled by the following equation:

$$k = \frac{D}{P} + g$$

where k = the investors' required return on common equity

D = the dividend per share paid in the next period

P = the current market price per share of the common stock

g = the investors' mean expected long-run growth rate in dividends paid per share.

Id., Appendix A, p. 1. Some of the components of the model, like the current price and the current dividend in effect during the period, are easily measured. *Id.*, pp. 7-9. The investors' expectations of the growth in dividends over the next year and over the rest of the investors' holding period, however, are not directly measurable. *Id*., pp. 9-12. Each of these components to the model will be discussed below.

a. Mr. Newhard's Dividend Yield Calculation Provides A Reasonable Average Of Recent Dividend Yields

The dividend yield component of the DCF model is determined by dividing the indicated dividend by the current market price of the stock.[53] *Id*., pp. 9-11.. Using the dividend yield based on the information of one point in time will result in a volatile yield that will be susceptible to the peculiarities of one day events that might affect the market. *Id*., pp. 7-8. To avoid any abnormalities associated with using one day information, it is appropriate to use the average of several months of dividend yields. *Id*.

Mr. Newhard provided the most recent twelve months of dividend yield information through June of 2005 for this comparison group's common stock in his response to Exh. AG-8, Sch. 2. From this information, the most recent six month dividend yield average is 3.57 percent, while the most recent twelve-month average is 3.67 percent. *Id*. Based on these yields, a 3.62 percent dividend yield adjusted for the growth rate discussed below is an appropriate basis for the Department to use in its analysis of the DCF model. Exh. AG-8, pp. 8-9.

b. Mr. Newhard Provided A Reasonable Estimate Of The DCF Growth Rate

The growth rate used in the DCF model is the investors' mean expected long run growth rate in dividends paid per share. *Id*., p. 9. Since it is impractical to measure all of the investors'

[53] The indicated dividend is determined by annualizing the level of the current quarterly dividend per share being paid. *Id*., p. 7.

expectations regarding their growth rate estimates, it is necessary to use proxies for those expectations. *Id.* These proxies include historical and forecasted measures of dividends, earnings, and book value per share growth rates as well as the growth rates from retained earnings. *Id.*, pp. 9-13.

Mr. Newhard chose the growth from retained earnings as the best single proxy of the growth rate for the constant growth rate DCF. *Id.*, pp. 9-14. The growth from retained earnings can be represented by the formula:

$$\text{Growth From Retained Earnings} = \text{Return On Common Equity} \times \text{Retention Ratio}$$

$$= \frac{\text{Earnings Per Share}}{\text{Book Value Per Share}} \times \frac{\text{Earnings Per Share} - \text{Dividends Per Share}}{\text{Earnings Per Share}}$$

Id., p. 12. He found that the growth from retained earnings did not have the problems that the other proxies for the DCF growth rate, when used as the single proxy in the constant growth rate DCF.[54] *Id.* He used 5.10 percent, the average of the five-year historical and forecasted rate of

[54] The growth in dividends can be the result of an increase in earnings per share available for common shareholders or an increase in the payout ratio. Exh. AG-8, pp. 9-12. However, since growth in dividends per share which results from an increase (or decrease) in the payout ratio cannot be continuous, a simple measure of the historical growth rate of dividends per share could lead to an incorrect estimate of the expected long-run DCF growth rate. *Id.* Since dividends are paid out of earnings, the growth in earnings could be a proxy, but with wide swings in earnings in the short-run and the possibility for changes in the payout ratio, earnings will not always be a good proxy either. *Id.* Finally, since dividends and earnings are derived from the book investment, the growth in investment is another possible proxy for the DCF growth rate. *Id.*

growth from retained earnings of 4.80 percent and 5.40 percent, respectively for the comparison group of gas distribution companies. *Id*., pp. 13-14 and Sch. 3.

Mr. Newhard then added to that amount the expected growth from stock issuances when the price of the stock is different from one. *Id*., p. 12-13. This component can be modeled by the formula: s x v, where "s" is the growth in the amount of common stock outstanding, and "v" is one minus the book to market ratio of the common stock. *Id*. He estimated this amount to be a negative 0.14 percent for the comparison group. *Id*., pp. 13-14 and Sch. 4. Adding the growth from stock issuances of -0.14 percent to the growth from retained earnings of 5.10 percent, Mr. Newhard found that 4.96 percent was a reasonable estimate of the DCF growth rate. *Id*.

The cost of equity estimate is then calculated by adding together the growth rate to the prospective dividend yield. The components are combined as follows to estimate the cost of equity:

Shareholders experience positive and negative growth in two ways, through the retention of earnings and through the issuance of more common equity, however, if new stock is not issued at the book value per share, as it is currently for most utility stocks, the book value per share growth rate will not be a good proxy either. *Id*.

$$k = \frac{D_0}{P} \times (1 + 0.5 \times g) + g$$

$$= 0.0362 \times (1 + 0.5 \times 0.0496) + 0.0496$$

$$= 0.0866$$

Id., p. 14. Thus, Mr. Newhard found that an 8.66 percent cost of equity was a reasonable estimate for the comparison group, using the constant growth rate DCF methodology. *Id*.

ii. Mr. Newhard Performed A Two-Step Discount Cash Flow Analysis

Mr. Newhard also performed a two-step DCF analysis. *Id*.,pp. 14-16; Appendix B. The two-step DCF analysis allows for investors' growth rate expectations that might be different during certain periods, where for instance their short-run expectations might be different from the long-term expectations for the investment in question. *Id*., p. 14. Mr. Newhard assumed for the comparison group that, for the first five years, investors expect dividends per share to grow at a rate equal to an average of available five-year earnings forecasts. *Id*., p. 15. He used the latest average five year forecast earnings per share growth rate estimates of 5.01 percent from investment analysts' surveys for this first step of the two step DCF methodology. *Id*. For the second step of the formula, the long-run growth rate for all years after the first five-year period, Mr. Newhard used a 5.57 percent growth rate estimate, based on the investors' expectations of the long-run growth rate in the economy. *Id*. Combining the current price with investors' short-term and long-term expectations, the two-step DCF analysis yielded a 9.21 percent cost of equity estimate. *Id*., p. 16.

iii. Mr. Newhard's Range Of Costs Of Equity For The Comparison Group

Mr. Newhard developed a range of estimates of the cost of common equity for the comparison group based on the results from his constant growth rate DCF and his two-step DCF analyses. *Id*. The range was from 8.66 percent to 9.21 percent. *Id*. He checked these results with his cost of equity analysis of NiSource. *Id*., p. 18. Using the constant growth rate DCF results of 7.77 percent and the two-step DCF results of 9.49 percent, Mr. Newhard found that this range of costs of equity of 7.77 percent to 9.49 percent supported the results from the comparison group of gas companies. *Id*. As will be discussed below, the range of 8.66 percent to 9.21 percent for the comparison group cannot be used without recognizing the differences in investment risk and expected returns between Bay State Gas Company's regulated gas distribution business those of the companies in the comparison group.

iv. The Cost Of Equity For The Comparison Group Of Gas Companies Is Significantly Higher Than That Of Bay State Gas Company's Gas Distribution Business

Mr. Newhard recommended that the cost of equity be set for cost of service purposes at 8.66 percent, at the bottom end of the range of estimates for several reasons. *Id*., pp. 16-18. First, he recognized that the rate that the Department is setting is for the Company's regulated gas distribution business, considered to be one of the, if not the least risky of any of the businesses reviewed by stock analysts. *Id*. The companies in the comparison group are invested in more than the regulated gas distribution business. Some have significant investments in power generation, and others have investment in the marketing and sales of energy which are much more risky. *Id*. These investments and the earnings requirements in other substantially more risky businesses are driving investors' expectations. *Id*. This causes the costs of equity to rise with these increasing investment risks. *Id*. Therefore, the estimates from Mr. Newhard's DCF analyses like any analysis of this group (including Mr. Moul's results) will tend to overstate the cost of equity for Bay State Gas Company's gas distribution operations.

Mr. Newhard also recognized that the addition of the numerous base rate adjustments that are proposed by Bay State Gas Company in this case will significantly reduce the Company's cost of capital. *Id*., pp. 17-18. With the addition of the new rate recovery mechanisms, the Company will go from collecting approximately 60 percent of its costs dollar for dollar to almost 85 percent of its costs dollar for dollar. *Id*. The remaining base rate elements, moreover, will receive annual increases based on the rate of inflation. *Id*. As Mr. Newhard recognized, none of the companies in the comparison group, and for that matter none of the gas companies in the nation get this type of cost recovery treatment. *Id*. This major shift of risk to the customers cannot be done without a significant reduction in the cost of common equity. *Id*. Therefore, given the lower risk of the gas distribution service for which the Department is setting rates in this case, Mr. Newhard recommended that 8.66 percent, the lower end of his range of cost of equity estimates is the appropriate rate to use to determine Bay State Gas Company's overall cost of capital. *Id*., p. 18.

d. Mr. Moul's Analysis Is Fundamentally Flawed And Should Be Rejected By The Department.

i. Discounted Cash Flow Analysis

Mr. Moul performed a DCF analysis on a group of companies that he deemed were comparable to the Company in investment risk, using the same group of gas companies that Mr. Newhard used. Compare Exh. AG-8, pp. 5-6 and Exh. BSG/PRM-1, pp. 13-20. *Id*. Appendix E, p. 1. Mr. Moul used the same equation as Mr. Newhard for performing his constant growth rate DCF analysis:

$$k = \frac{D}{P} + g$$

where k = the investors' required return on common equity

D = the dividend per share paid in the next period

P = the current market price per share of the common stock

g = the investors' mean expected long-run growth rate in dividends paid per share.

Id., Appendix E, pp. 1-2. Each of Mr. Moul's components to the model will be discussed below.

Mr. Moul provided the most recent twelve months of dividend yield information for this comparison group's common stock in his response to Exh. AG-10-22.. From this information, the most recent three-, six-, and twelve- month dividend yield averages are 3.59 percent, 3.60 percent and 3.71 percent, respectively . *Id*. Based on an average of these updated yields, the 3.62 percent dividend yield adjusted for the growth rate discussed below is an appropriate basis for use in Mr. Moul analysis of the DCF model, exactly the same dividend yield used by Mr. Newhard in his DCF analysis. AG-8, Sch. 2.

The growth rate used in the DCF model is the investors' mean expected long run growth rate in dividends paid per share. Exh. BSG/PRM-1, Appendix E, p. E-9 ("viewed in its infinite form, the DCF model is represented by the discounted value of an endless stream of growing dividends"). These proxies include historical and forecasted measures of dividends, earnings, and book value per share growth rates as well as the growth rates from retained earnings. *Id.*, pp. 28-29. Mr. Moul provided some of these proxies for the comparison group.

	Five-Year Historical	Ten-Year Historical	Five-Year Projected
Dividends Per Share	2.20%	2.10%	2.30%
Earnings Per Share	5.20	5.50	4.98[55]
Book Value Per Share	5.10	4.00	7.90

Exh. BSG/PRM-2, Sch. 8 and 9 .

Mr. Moul has again proposed a DCF growth rate estimate without any basis, choosing the highest available estimates and ignoring historical data to determine his averages. The upward bias in his DCF growth rate estimate is obvious. His growth rate estimate for the comparison group of 5.75 percent is 355 basis points above the historical dividend growth rate and 345 basis

[55] The five-year projected earnings forecast can be determined by averaging together the survey results from the five-year projections of 4.99 percent from IBES/First Call, 5.06 percent from Zacks, and 4.89 percent from Reuters. [4.98 = (4.99 + 5.06 + 4.89) / 3].

points above the projected dividend growth rate. *Id*. Mr. Moul provides no evidence to justify the magnitude of gigantic differences in growth rates.

A simple and objective test of the reasonableness of his growth rate estimate is to simply average the historical and forecast growth rates for dividends, earnings, and book value per share. Averaging together these values (as indicatd in the table above), a representative growth rate would 4.36 percent. [(2.20 + 2.10 + 2.30 + 5.50 + 5.20 + 4.98 +5.1+ 4.0 + 7.9) / 9]. Clearly, Mr. Moul's DCF 5.75 percent growth rate, based on the short-term earnings per share forecasts, are over-inflated, and should be rejected by the Department. The Department should reject Mr. Moul's proposed DCF analysis and instead rely on Mr. Newhard's more complete and better supported DCF analyses.

ii. Capital Asset Pricing Model Analysis

Mr. Moul performed a Capital Asset Pricing Model analysis to estimate the cost of equity for his comparison group. Exh. BSG/PRM-1, pp. 44-48 and Appendix H. The Department should reject Mr. Moul's CAPM analysis not only because he applied the model poorly, but also because the CAPM's underlying assumptions depart so substantially from the real world that the model cannot reliably determine the cost of common equity for a utility company.

The CAPM is a risk premium approach used to determine the cost of assets. *Id*. Like other risk premium approaches, it is based on the assumption that investors require a higher return on their investment for them to hold assets of greater risk. *Id*. The CAPM approach breaks the total risk of an asset into two components, systematic risk and unsystematic risk. *Id*., Appendix H, p. 1. Systematic risk represents the variability of the return on an investment associated with the effect of economy-wide forces (*e.g.* information and interest levels). *Id*.

Unsystematic risk, on the other hand, represents the risk associated with asset specific risks (*e.g.* risks that are specific to a particular company like industry competition and the quality of a company's management). *Id*. Portfolio theory assumes that an asset is evaluated in the context of a well-diversified portfolio where the unsystematic risks associated with individual assets cancel each other out. *Id*. Under the same theory, since unsystematic risk can be avoided with a well-diversified portfolio, the CAPM model should only focus on the amount of systematic risk associated with the asset. *Id*.

The CAPM measures the systematic risk of an asset with a factor known as beta. *Id*., pp. 2-3. The Model defines the beta value of all assets, on average, as equal to 1.0. *Id*. In the Model, an asset with a beta of 1.0 will have a return, which will have variations equal to the variability of the returns of the market as a whole. *Id*. The price of an asset with a beta of 1.0 will increase by 10 percent when the market value as a whole increases by 10 percent. *Id*. Conversely, the asset's price will decrease by 10 percent when the market value goes down by 10 percent. *Id*. Furthermore, the price of an asset with a beta of 1.5 will increase by 15 percent when the market increases 10 percent and decrease 15 percent when the market decreases 10 percent. *Id*. If the beta is 0.5, the asset's price will increase 5 percent when the market increase 10 percent, and it will decrease by 5 percent when the market decreases by 10 percent. *Id*. The CAPM theory provides a formula to determine the return on the asset that is required by the market. *Id*. The formula is as follows:

$$r = rf + b \times rp$$

where r = the market required return on the asset

rf = the return on risk-free investments

b = the beta of the asset

rp = the expected difference between the return on the market as a whole and the return on the risk-free asset.

Id. This is the formula that Mr. Moul used to perform his CAPM analysis in this case. *Id*.

The CAPM theory and the formula derived from the theory are based on many assumptions. Although some of these underlying assumptions of the CAPM are true in the real world, several of them just do not hold true for the application of the Model in the case of an investment in the comparison group's common stock. Without these assumptions that are fundamental to the CAPM, the use of the Model is inappropriate, and must be rejected by the Department.

The Department has found that the assumptions underlying the CAPM are too "heroic" to make its application to a utility stock useful. *Boston Gas Company*, D.T.E. 03-40, p. 360 (2003); *Boston Gas Company*, D.P.U. 96-50, p. 125 (1996); *Berkshire Gas Company*; D.P.U. 92-210, pp.148-150 (1993); *Boston Gas Company*, D.P.U. 92-78, p. 113 (1992); *Boston Gas Company*, 88-67 (Phase I), p. 184 (1988); *Commonwealth Electric Company*, D.P.U. 956, pp. 54-55 (1982). In *Commonwealth Electric Company*, the Department found that the following assumptions too unrealistic:

(1) investors can borrow and lend an unlimited amount of money at a risk-free rate;

(2) investors evaluate equity/security portfolios according to the means and standard deviations of portfolio returns;

(3) there are *no* income taxes; and

(4) investors are "single period expected utility of terminal wealth maximizers" -- that is a 100 percent liquidating dividend is paid at the end of the period.

Id., p 54. [emphasis added]. Clearly, investors would find highly desirable a world with unlimited investor borrowing capacity and no income taxes, but reality is otherwise. The CAPM assumptions try to fit all investors into one neat package to conform to the Model requirements. The requirements that investors evaluate their portfolio returns and liquidate their investments at the end of the holding period obviously cannot contain the many different investors with many different analysis techniques and investment requirements. Mr. Moul's analysis never attempts to address any of these fundamental problems with these assumptions of the Model. The Department should reject the use of the CAPM analysis as a methodology for determining the cost of equity for utilities, as it has done in the past. *Id.*

iii. Comparable Earnings Analysis

Mr. Moul also performed a Comparable Earnings analysis. Exh. BSG/PRM-1, pp. 48-52 Appendix I. He bases this comparable earnings analysis on certain stock indicators used by *Value Line Investment Survey*. Exh. BSG/PRM-1, pp. 50-52. The Department has repeatedly rejected the Comparable Earnings approach. *Boston Gas Company*, D.T.E. 03-40, pp. 360-361 *Gas Company*, D.P.U. 96-50, pp. 131-132 (1996); *Cambridge Electric Light Company*, D.P.U. 92-250, pp. 160-161 (1993); *Bay State Gas Company*, D.P.U. 92-111, pp. 280-281 (1993); *Berkshire Gas Company*, D.P.U. 92-210, p. 155 (1993); and *Berkshire Gas Company*, D.P.U. 905, pp. 48-49 (1982). The Department specifically rejected Mr. Moul's use of the Comparable Earnings Approach as unreliable because the earned return on common equity did not necessarily equal the companies' cost of capital. *Berkshire Gas Company*, D.P.U. 905, pp. 48-49

(1982) *citing Boston Edison Company*, D.P.U. 1991, p. 56 (1979). Mr. Moul has provided no reason in this case for the Department to change its well-founded precedent. The Department should reject Mr. Moul's Comparable Earnings analysis, since its results are unreliable.

iv. Risk Premium Analysis

Mr. Moul also provided a Risk Premium Analysis. Exh. BSG/PRM-1, pp. 38-44 and Exh. BSG/PRM-1, Appendix G. Although he represents this methodology as an analysis separate and distinct from the CAPM analysis, it is essentially the same analysis. The cost of equity capital is equal to the yield on utility bonds plus an equity risk premium. *Id*. His risk premium analysis substitutes utility bonds for U.S. Treasury bonds and he substitutes the Standard and Poor's utility index for the stock market return. *Id*.

The Department has reviewed and rejected Risk Premium analyses like Mr. Moul's many times before. See *Boston Gas Company*, D.T.E. 03-40, p. 359; *Boston Gas Company*, D.P.U. 96-50, p. 128; *Massachusetts Electric Company*, D.P.U. 95-40, p. 97 (1995); *Boston Gas Company*, D.P.U. 93-60, p. 261 (1993); *Bay State Gas Company*, D.P.U. 92-111, pp. 265-266; *Berkshire Gas Company*, D.P.U. 92-210, pp. 138-139 (1993); and *Berkshire Gas Company*, D.P.U. 90-121, p. 171 (1991). Each time the Department has found that the risk premium approach overstates the amount of company-specific risk and, therefore, overstates the cost of equity. *Id*. The Company has provided no new analyses and no new argument. The Department should again reject Mr. Moul's Risk Premium analysis. *Id*.

v. Mr. Moul's Other Adjustments To His Cost Of Equity Results

Mr. Moul increased his cost of equity recommendations by creating new adjustments for certain cost or risk factors. These adjustments increase the cost of equity for his comparison group and ultimately for the Company. He proposes that his market-to-book ratio adjustment be applied to his DCF analysis, which would inflate his DCF results by 64 basis points. Exh. BSG/PRM-1, pp. 40-41. He also leverages and unleverages the betas used in his CAPM analysis, which inflates the results of the CAPM by 78 basis points or 0.78 percent [(0.85 - 0.72) x 6%]. Exh. BSG/PRM-1, pp. 45-46. Mr. Moul, however, ignores what is probably the most important single factor that investors consider when investing in the companies in the comparison group - the companies' non-utility businesses increase their risk for these companies.

The Department is setting rates for the regulated gas distribution business in this case. The allowed return on common equity should reflect only the market-required return for that business. Since the companies in Mr. Moul's comparison group are invested in other non-utility businesses, their costs of equity for the overall operations of the corporation will diverge from that of the utility operations. Whether the non-utility businesses are energy marketing and sales or power generation, these other businesses have higher required returns on common equity. See Section E.2.b.iv., *supra*. Mr. Moul completely ignores this critical factor, which would lower the cost of capital for the regulated gas distribution business.

e. Summary and Recommendation

The Department should reject the Bay State Gas Company's proposed cost of equity and Mr. Moul's recommendations regarding the cost of capital. Instead, the Department should base its decision on the analyses testimony of Mr. Newhard and find that allowed return on common equity should be 8.66 percent.

H. RATE DESIGN

1. Residential Customer Charge Increase Should Be Mitigated

The Company proposes to increase the customer charge for the Residential Heating class customer by $4.63 per month, and for the Residential Non Heating class by $4.14 per month. For low use Residential Heating customers this represents an increase in the distribution service portion of the bill (excluding all adjustment clause charges) in the range of 62 % for a customer with no use to 14% for a low use customer.[56] The average annual increase for the total bill for these customers ranges between 62 percent and approximately 5 percent. Exh. BSG/JAF-2, Sched. JAF 2-6. The Company designs its proposed rates to collect the fully allocated cost of service ("ACOS") for each rate class.[57] As part of the design process the customer charge[58] is set first. Mr. Ferro, the Company's rate design witness, states that he compared each class's current customer charges with the customer charge component from the ACOS. Exh. BSG/JAF-2, Sched. JAF-2-2 For the residential classes the difference between the current rate is significant and, for rate continuity reasons, Mr. Ferro sets the proposed customer charge to collect approximately 50% of the class's full allocated customer costs. Id. The remaining 50 percent of the customer costs are included in determining the first block charge. Id.

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[56] These increases are based on the distribution service portion of a customer's average annual bill for usage levels illustrated in the Company's bill frequency tables, Exh. BSG/JAF-2, Sched. JAF-2-6. The usage levels were 0 therms for the no use customer calculation and 472 therms for the low use customer in the 12.93 percent bracket.

[57] The Delivery Allocated Cost of Service Study is Exh. JLH-2, Sched. JLH-2-2. This study develops the cost to serve each rate class based on the test year proforma costs and the Company's proposed cost of capital. The allocated costs are developed using the same rate of return requirement for each class. Rates set at the class cost would generate the same rate of return on their allocation of the rate base.

[58] Customer costs include the costs of billing, meter reading and customer service.

Although the Company's method is consistent with Department precedent[59], the bill impacts for low use residential customers are too high,[60] especially when the potential impact of rising gas costs which naturally leads to conservation and lower usage levels is considered.[61] The Department should provide relief from this winter's impending gas price increases.[62] By holding customer charges at the current level or by limiting the increase to that equal to the overall increase granted to the Company for the residential heating class, bill impacts for the lowest use customers will be softened beginning November first, the same time the new peak season CGA goes into effect.

2. THE COMPANY'S RESIDENTIAL RATE DESIGN SHOULD BE MODIFIED TO ENHANCE SIMPLICITY AND REDUCE BILL IMPACTS

In designing the Company's proposed rates Mr. Ferro made a judgement about whether each customer class would have flat or blocked rates.[63] Mr. Farro testified that he decided that flat rates were appropriate for the Commercial and Industrial rate classes based on the desire to simplify the rate design and the concern that the various C&I classes had "large variations in the percentages of bills ending in the first block." Exh. BSG/JAF-2, p. 9. For the residential classes, Mr. Ferro determined that the customer costs not recovered through the customer charge

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[59] *Boston Gas Company*, D.T.E. 03-40, p. 386. In this case the Department reduced the requested increase to the residential heating class customer charge from $16.98 to $12, almost $5.00. The result was that the customer charge increased by $1.93, less than half of the Bay State proposal.

[60] The increase to small business low load factor customers is similar and should be similarly mitigated. For impacts, see Exh. BSG/JAF-2, Sched. 2-6 for the G/T-40 class.

[61] In the Company's last rate case the Department approved a $1.00 increase to the residential heating class's customer charge. *Bay State Gas Company*, D.P.U. 92-111, p. 327 (1992).

[62] EIA estimates that the average residential price for natural gas will be almost 14% higher in 2005/06 than in 2004/05. http://www.eia.doe.gov/emeu/steo/pub/contents.html

[63] Blocked rates divide the energy charges into segments based on usage levels and generally result in a head block and a tail block. The usage per block is set so that 50 percent of the class's usage terminates in the head block and the remaining 50 percent would be billed in the tail block. Exh. BSG/JAF-2, p. 9. Flat rates have a single energy charge for all usage.

should be included in the head block, consistent with Department precedent. *Berkshire Gas Company*, D.T.E. 01-56, p. 140. The final rate design proposal for the residential heating class includes a $12.10 customer charge and volumetric rates in two blocks--the head block is $0.3183 per therm and the tail block is $0.2224 per therm. The Company's proposal eliminates the current seasonal differentiation in the block rates and incorporates a base rate scheme that is seasonally differentiated by differences in the size of the head block. The residential heating winter head block rate applies to the first 125 therms of use in the month. The summer head block rate applies to the first 30 therms. Exh. BSG/JAF-2, Sched. 2-7, p.1. The residential non-heating class's rates are designed in a similar fashion resulting in a customer charge of $11.00 per month, the first block rate of $0.2393 per therm and the tail block rate of $0.1928 per therm. According to the Company's calculations the proposed residential heating rates will increase a typical residential heating customer's annual total bill by approximately $54, assuming gas costs are at the same level as they were during the test year. *Id.* The residential non-heating typical customer's annual bill will increase by an estimated $24. *Id.*, p. 2.

The Attorney General requested that the Company provide a simple flat rate design for the residential classes. AG-9-18. The Company's response indicated that not only is the design simpler to understand, it produces slightly lower bill impacts for all but those customers with higher than average use. RR DTE-122. The Department, therefore, should adopt flat rates for the residential classes to simplify the rate design and as an additional means to mitigate the impact of any distribution rate increase at time peak gas prices go into effect.

3. Low-income Discount Rate

a. Standardization of the Low-Income Discount Rate

On August 8, 2003, the Department issued an order establishing a computer matching program for electric and gas distribution companies to facilitate the enrollment of eligible customers in utility discount rate programs. D.T.E. 01-106-A. The Department further required that utilities work with the Executive Office of Health and Human Services ("EOHHS") and exchange information so that customers could be automatically enrolled. D.T.E. 01-106-B, pp.11-12.

The Department should standardize both the low-income discount and the manner of collection for all gas and electric companies. Despite the Department's efforts to standardize the low-income rate, there appears to be considerable discretion left to distribution companies with regard to the determination of the value of the low-income discount rate. As a result, disparities are apparent in the value of the discount rate in different service territories across the Commonwealth. Such disparities are akin to discrimination based on economic status and location. Over the past several years gas prices have increased and have been extremely volatile. *See* www.mass.gov/dte/gas/cgac_page.htm for interim CGA rate adjustments during the past several years. It is fundamentally unfair that a low-income customer in KeySpan Energy Delivery's territory receives a 40 percent discount on the base rate portion of the bill, while a similarly situated customer in Bay State's territory may receive a 20 percent discount as measured on an average test year level of base rate plus average gas costs. *See* D.T.E. 03-40, p. 388. Moreover, it is similarly unfair to require the ratepayers of other rate classes be required to subsidize a higher or lower discount rate depending on which distribution service territory the ratepayer resides.

Low-income discount rates should, as a matter of public policy and administrative efficiency, be uniform and the Department should require that all distribution companies provide a similar, flat, low-income discount rate. The Department should avoid the inequities that result from disparities in the receipt of a statutorily mandated discount rate.

The Attorney General supports the Company's efforts to provide low-income consumers with a meaningful discount, especially in light of recent experience with constantly rising volatile gas prices. As a result of the efforts of Massachusetts utilities and EOHHS matching program, several utilities are seeking the Department's approval to recover additional costs through separate reconciling rate mechanisms.[6] Low-income consumers are entitled to equitable treatment across the state and recommends that the Department move the recovery of the total amount of Bay State's proposed discount from the base rates to the LDAC. Collecting the total amount of the allowed discount cost through the LDAC will support the implementation of uniform discount allowances across all utilities in the state and permit the reconciliation of actual discount costs that may vary over time as the level of eligible customers changes and eligible costs may vary from time to time. The Department should investigate: the most equitable level of low-income discount, based on balancing the burden from any increase to the discount level borne by all other customers along with the rising commodity cost; whether the discount should continue to be fixed and only relate to base rates or whether it should be expanded to include the cost of energy. Recent gas forward month futures prices have exceeded most recent winter prices, portending higher prices for customers in the upcoming winter. The Department should

[6] *See* D.T.E. 05-55 NSTAR, request for approval of Residential Assistance Adjustment Clause tariffs (filed August 16, 2005) and D.T.E. 05-56, MECo., request for Department approval of Residential Assistance Adjustment Provision, tariff number M.D.T.E. No. 1086 (filed July 25, 2005)

act quickly to permit utilities to implement any new programs at the beginning of the winter. If the Department is reluctant to open generic proceedings, then it should require a fully reconciling low-income discount recovery mechanism be implemented as part of the Company's LDAC.

b. The Company's Proposal

The Company proposes to simply maintain its existing low-income customer classes and their associated subsidized, 20 percent burner-tip discount rate. Exh. BSG/JAF-2, at 12. Tr. 10, p. 1717. Currently, this amounts to approximately a 60% discount on the distribution portion of the customers' bills. Tr. p. 1719. Consistent with its current practice, the Company proposes to discount only the base rate portion of the qualifying low-income customers bill.

The Company will continue to recover the subsidy provided to low-income customers from all other tariff customer classes. Exh. BSG/JAF-2, p. 12. The subsidy is allocated to classes based on distribution rate base and then added to the volumetric components of each classes rate structures. *Id.* at 12-13. The allocation of the residential low-income discount has had a substantial impact on class bill impacts. In fact, the allocation of the residential low-income discount has pushed some classes above the 6 percent cap increase to each classes total revenues. *Id.*; Exh. BSG/JAF-2, Sched. JAF-2-1.

As part of the EOHHS matching program, the Department allowed companies to collect the change in level of discount costs since their last base rate cases through the LDAC for gas companies and as part of the reconciliation filings for electric companies during the interim period before the next base rate case. D.T.E. 01-106-B, p. 9; *See also* Tr. 19, pp. 2984-2985. Bay State has made no special provision for increased levels of participation in the discount program related to the EOHHS match program; rather, Mr. Ferro testified that the Company intends to file for recovery of any increased discount costs in its upcoming Peak CGA/LDAC filing. Tr. 19, pp. 2984-2985. The Company's proposal to split the recovery of the low-income discount between base rates and the LDSC should be denied. For administrative ease and in support of a uniform application of the Department's low-income policies, as discussed above, the Department should require the Company to revise its rate design and tariff proposals to provide for the full recovery of the Department approved low-income discount through the Company's LDAC.

I. THE DEPARTMENT SHOULD OPEN AN INVESTIGATION INTO BAY STATE'S SERVICE QUALITY

1. THE DEPARTMENT SHOULD SET A REQUIRED STAFFING LEVEL FOR THE COMPANY TO PREVENT SERVICE QUALITY FROM DECLINING.

The Department should require the Company to maintain staffing levels at current levels so that the Company's service quality does not decline. Further reductions in staffing levels should be prohibited unless and until the company demonstrates to the satisfaction of the Department that any staffing reductions or outsourcing are consistent with all collective bargaining agreements and will not put service quality and reliability at risk.[7] Tr. 16, pp. 2658-59.

The Legislature explicitly integrated the provisions governing staffing levels with the requirements regarding a company's service quality. The statute states that,

[7] The Company is considering outsourcing the call center in an agreement with IBM. Tr. 1, p 179. This arrangement raises questions about who will be responsible for meeting the service quality requirements and could have a negative effect on service quality in the future.

> In complying with the service quality standards and employee benchmarks established pursuant to this section, a distribution, transmission, or gas company that makes a performance based rating filing after the effective date of this act shall not be allowed to engage in labor displacement or reductions below staffing levels in existence on November 1, 1997, unless such are part of a collective bargaining agreement or agreements between such company and the applicable organization or organizations representing such workers, or with the approval of the department following an evidentiary hearing at which the burden shall be upon the company to demonstrate that such staffing reductions shall not adversely disrupt service quality standards as established by the department herein.

G.L. c. 164, § 1E (b). The Legislature recognized that without this mandatory requirement, companies would attempt to reduce costs by decreasing staffing levels, which would adversely affect the quality of service provided to ratepayers.[8] The generic guidelines ("Guidelines") issued by the Department regarding staffing levels in *Service Quality Standards for Electric Distribution Companies and Local Gas Distribution Companies*, D.T.E. 99-84, pp. 41-42 (June 29, 2001), state that: "Consistent with G.L. c. 164, § 1E, staffing benchmarks will be established on a company-specific basis and will be determined by the then-effective collective bargaining agreement for each company." *Id*.

It is now time for the Department to act consistent with G.L. c. 164, § 1E (b), and its regulations and establish minimum staffing levels. The record evidence in this case establishes that Bay State's outsourcing of jobs has had fatal consequences and further staffing reductions, without Department review, may pose a threat to public safety. *See* Exh. AG-2; Exh. UWUA-4, p. 28 (In Attleboro, two people lost their lives, seven people were injured, and 68 other houses

[8] *See* Letter to Berkshire Gas Company from Representative Daniel E. Bosley, copied to Chairman Paul Vasington, April 22, 2003, stating that G.L. c. 164, § 1 E (b) applies to a company that makes a performance based rate filing. Pursuant to the provisions of 220 C.M.R. 1.10 (3), the Attorney General asks the Department to incorporate this letter by reference.

were damaged after Bay State outsourced its line-locator function); Exh. UWUA-4, pp. 2-3; Tr. 16, p. 2654.

2. THE DEPARTMENT SHOULD OPEN AN INVESTIGATION INTO BAY STATE'S SERVICE QUALITY

The Company has had many problems with maintaining service quality at the Springfield call center and maintaining gas safety and reliability through leak management. *See* Tr. 1, p. 65, 67-68; Tr. 16, pp. 2612-13, 2662-63. The evidence in this case clearly demonstrates problems with the accuracy of Bay State's numbers in its annual service quality filing. Tr. 20, pp. 3331-32 (disconnecting the telephone trunk line to reduce the amount of calls received); Tr. 20, p. 3147 (counting calls for billing where the call center initially took a message and then called the customer back after five o'clock in the evening). Because it lacked the appropriate level of staff members, the Company removed a trunk line at its call center at one point so that customers would receive a busy signal and less calls would go into the queue.[9] Tr. 20, pp. 3331-32. When compared to the telephone service factor benchmarks of other Massachusetts utilities, Bay State's is one of the lower benchmarks.[10] A call never received is not counted for purposes of the Department's Service Quality Standards. The record evidence indicates that Bay State performs far worse than it claims in its filed reports (*Id.*; Tr. 20, p. 3147) raising doubts about the

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[9] Bay State's affiliates in Maine and New Hampshire have also had problems meeting their service quality levels such that they were required to pay penalties or refund money to ratepayers for not complying with the required service quality standards in those states. Tr. 10, p. 1644; Tr. 12, p. 2034.

[10] Bay State's call answer benchmark, based on historical company data, is 69% of the calls answered in 30 seconds. Tr. 12. p. 2035. Bay State's New Hampshire affiliate has a benchmark of 80% of calls answered in 30 seconds and is monitored monthly. Tr. 12, p. 2013.

validity and helpfulness of other service quality metrics and raising the possibility that Bay State may face service quality penalties.[11]

Ensuring the safe operation of the Commonwealth's electric and gas systems is one of the Department's most important roles and responsibility. On a number of occasions, the Attorney General has previously asked the Department to conduct evidentiary adjudications to investigate utility service quality, each time, the Department has either failed to respond or refused to investigate the service quality filings of the utilities (*2002 Service Quality Reports for Electric Distribution and Local Gas Distribution Companies*, D.T.E. 03-10 through D.T.E. 03-23, and *2003 Service Quality Reports for Electric Distribution and Local Gas Distribution Companies*, D.T.E. 04-12 through D.T.E. 04-25), including a specific request that the Department investigate Bay State's Service Quality filings and open an evidentiary hearing. *See Bay State Gas,* D.T.E. 03-10, Attorney General Comments. Contemporaneously with the Attorney General's request for an investigation, the Public Utilities Commissions of both New Hampshire and Maine opened investigations into Bay State affiliates and determined that the Company failed to provide adequate service.[12]

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[11] In addition to the Department's general supervisory authority over utilities (G.L. c. 164, § 76), the Electric Restructuring Act of 1997 ("Act") (Stat. 1997, chapter 164), G.L. c. 164, § 1E(c), provides that "each distribution, transmission, and gas company shall file a report with the department by March first of each year comparing its performance during the previous calendar year to the department's service quality standards and any applicable national standards as may be adopted by the department. The department shall be authorized to levy a penalty against any distribution, transmission, or gas company which fails to meet the service quality standards in an amount up to and including the equivalent of 2 per cent of such company's transmission and distribution service revenues for the previous calendar year."

[12] After conducting two separate investigations on service quality and billing practices, the Maine PUC concluded that Bay State's affiliate had service quality problems involving billing, meter-reading, and the call center and that the affiliate had to refund customers approximately $130,000 because of billing problems. Tr. 10, pp. 1643-45. In a settlement with the New Hampshire PUC, Bay State's New Hampshire affiliate paid $30,000 in fines from January to June 2003 (six times the monthly maximum fine of $5,000) for not meeting its call center service quality benchmark. Tr. 12, p. 2034.

The Department should open an investigation and audit the annual service quality filings to insure their accuracy and the corporate management that has tried to evade the Department's service quality requirements. *See Boston Edison Company*, D.P.U. 85-266-A/271-A (1986); *Commonwealth Electric Company*, D.P.U. 89-114/90-331/91-80 Phase One (1991). As part of that investigation, the Department should determine new standards/benchmarks of performance that are higher than the historical averages currently employed.

VII. CONCLUSION

Wherefore, for all the foregoing reasons, the Attorney General requests that the Department reject the Company's proposed rate increase, PBR plan, and all adjustment mechanisms.

Respectfully submitted,

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